SCOMM

#14:1

HOUSE RESOURCES COMMITTEE MEETING

ON

PRUDHOE BAY RESERVOIR MANAGEMENT

ROOM 118 - CAPITOL BUILDING

JUNEAU, ALASKA

August 6 and 7, 1979

Volume I

Pages 1 - 150

J & R Associates

P.O. Box 29 • Douglas, Alaska 99824

Judy Jones
586-6846

Rita Stoinich
789-0208

AGO 532113

August 6, 1979

3:00 p.m.

BY: MR. MILES

I will call the House Resources Committee to order. I would firstoff like to start by thanking the number of faces who have come up from the Lower 48 and various parts of the State. We certainly appreciate you joining us here in Juneau. The plans for the conduct of the hearing are essentially as follows. We'd like to hear from the gentlemen at the end of the table first. Mr. Joe Green, Mr. Hoyle Hamilton, with a brief overview of what reservoir engineering is all about in layman's language. Subsequently, we'd like to hear from Mr. van Poollen who is also sitting at the end of the table, followed by Dr. Doscher, the legislative consultant. Following those presentations, I'm advised, and I guess -- somebody from the industry correct me if I'm wrong, but we're going to have Paul Norguard, Brian Davies from SOHIO BP, Larry Smedley and then David Griffith. Is that -- that's essentially right. Time permitting and other unforeseen occurrences not occurring such as adjournment of the legislature, hopefully we'll wrap up the hearing sometime tomorrow. Others will be able to testify again, time permitting. I, at this time, just wouldn't even hazard a guess as to when various things

may happen. There are meetings going on on all floors right now, so we're all going to unfortunately have to lay a little bit loose insofar as the timing of the meetings are concerned. We'll keep the meetings posted on the second floor blackboard because we have to break and come back and break and come back and it's just an unfortunate occurrence during the special session. Briefly, to recap why we're here in the Resources Committee, I think we all understand the exteme difficulties of predicting a reservoir, especially one that we understand is so unique such as Prudhoe. There are just any number of different factors that go into production reservoir predictions and guesstimates or estimates. As a result, the State hired a number of people to do some professional work for us, those being especially Mr. van Poollen to specifically create a three-dimensional reservoir model and Dr. Dosher to work closely with the legislature and Mr. van Poollen to advise us on what the findings are and, I suppose, interpret them as much as possible for us. We're talking about a subject that may mean hundreds of millions of dollars if not billions of dollars. Even a slight variance or a slight change can have tremendous results. Obviously, the State's interest is in long-term maximum recovery. It's not the same, necessarily, as the industry. Of late, there have been a series of charges, if you will, and countercharges with

regard to Prudhoe Bay. My understanding right now, and maybe it will change over the course of the hearing, is that nobody really knows a thing for sure insofar as the reservoir is concerned. We're taking our best guesses, but before Mr. van Poollen completes his run and completes the three-dimensional model, we can't be too sure. Hence, it seems like only when all the facts are on the table, and that's what we're here for, can we make more reasonable estimates. That's essentially the purpose of why we are here. The hearing, then, represents more of an update on what those people contracted with the State are doing, what information they are finding. And with that, by way of introduction, I might ask if any of the other Committee members would like to make an introductory statement or comment. If not, then, I think we'll turn it over to you, Hoyle, and perhaps you can give us Reservoir One.

BY: MR. HAMILTON

Thank you, Mr. Chairman. I'm Hoyle Hamilton. I'm chairman of the Oil and Gas Conservation Commission. With me here today are Commissioner Kuggler sitting over there. He'll be running the projector for me shortly here. To my far right is Commissioner Lonnie Smith. To my immediate right is our staff reservoir engineer, Joe Green, and to my immediate left is Dr. van Poollen who is our consultant on this project. To my far left is Jeff Lowenfels with the

Attorney General's Office who is the legal advisor for the Commission. And to start this off, you asked for some type of an overview of what a reservoir more or less was and I prepared a little brief presentation I would like to go through and, following that, I have -- we have a presentation that Mr. Green will give which will bring you up to date on the -- a brief history and what we have done so far; our past studies and so forth with the reservoir, followed by what we have done with cross-sectional work to date and some pressure maintenance concepts followed by some of our computer analysis work and then Mr. van Poollen will follow that up with a presentation on some of the 3-D modeling work that we are doing. You can ask questions at any time duirng our presentation and we'll..... That's our brief introduction and I'd like to go to the first slide, if you would, Harry, and we'll start off with the..... (Slide show commences.) This, I think most of you are aware of. This slide indicates how the formation of oil in the ground..... You have sediments that have been deposited in the ground and they're compressed and move down in the lower parts of the earth where the temperature gets extremely high and eventually it's converted to oil over millions of years, and this shows you the very beginning. One thing this points out that -- why you find oil in sedimentary rocks because that's the origin of the oil,

initially, is in the sedimentary rocks. The next slide, Harry. This is a cross section in the earth. Now, this is after the oil has been formed and it has moved into a subsurface trap. That particular trap there, you'd call an anticline but, you see, it has a cap rock over the oil of hard shale that's impervious. The oil cannot move out of that trap and that's the type of things you look for in geophysics to drill and try to find your oil. Next slide. Now, this is a close-up of what oil looks like in the reservoir rock itself. It's not contained in a pool even though we call some of the reservoirs pools. It's contained among the sand grains, as you see here. You see the sand grains shown and the oil in between and along with that oil, you will always find water which we call connate water. That's the water that was originally deposited with the rock itself and it's usually surrounding each of the sand grains with the oil in between the sand grains. Next slide. This slide is to demonstrate what we call porosity. It's one of the factors that we measure in a formation or reservoir and, if you take a tray full of marbles, the marbles have space in between them just like that previous slide showed and you can pour oil or any other fluid in that tray and it can hold a considerable amount of fluid even though it's initially filled with marbles since the fluid flows in between the pore space,

and that pore space is what we term porosity or it's the percent of pores within the rock itself. Next slide. And this is similar to the previous slide, but I want to discuss the permeability aspect of the rock. You see the fluids contained in between the sand grains, those channels in between the sand grains, depending on how large they are, that will determine how easy the fluid can flow through those sand grains. If the channels are large, we call it a high permeability. In other words, it's very easy to flow through the rock. If it's tight, there's a lot of sedimentation in there and the pores aren't very large, it's a very low-permeability rock and the productivity from the reservoir will be very low. This illustrates another parameter that we attach to the reservoir and that's called saturation. You see a sample of a core taken from a reservoir and this particular one is a sandstone reservoir, fairly tight-looking, and an eye dropper has dropped a quantity of oil on the core and it had no oil in it before. As you can see, the discoloration there from the oil. The oil is soaking into that core and whatever oil it contains after it's been saturated, we call that the saturation of the reservoir. Now, this particular slide here indicates the core taken out of a very, very tight sandstone and this was cored with a coring tool and it's brought up to the surface and you make analyses on these core samples to

determine the properties of your reservoir rock. This happens to be a pemana (ph) core from Canada and it's such a tight sandstone that the only way you can produce any large quantities of oil from that reservoir is to artificially frac it or have some other means of stimulating the production. Next slide. This particular core here is from a core in Saudia Arabia. It's a limestone core and you can see the difference in the type of porosity you have here. You have large what we call bugs or bugular holes in the limestone and fractures. Reservoirs of this nature can produce at large rates and they can contain large volumes of reserves due to the fracture system and large holes in the limestone. Next slide. These are the principle types of reservoir trapping mechanisms you find. The more classical ones--the anticline, the fault and the stratigraphic trap, and I'll have a slide demonstrating each one here. This is your anticline. It's similar to the previous slide we had showing some oil trapped underneath the surface. It's just a curvature that's been formed with the rocks flexing underneath the ground surface. Oil accumulates in this flexure and it's trapped there by an impervious overcovering of rock. Next slide. This happens to be a surface anticline that's been exposed. Now, these same type of anticlines, if they exist down in the earth, will trap oil in them and you can see the -- part of the cap rock has been

eroded and it's around the very edge, but the center of the anticline is still in existence and this particular one comes from Wyoming. It's the Big Horn Basin in Wyoming. Sheep Mountain, they call it. Okay, Harry. This is another trapping mechanism. This is a fault and anyone living in Alaska, I think, and California, you're quite familiar with faults, but they do play a very active role in trapping oil. You can see where the slippage has occurred. The formation that has the little lines through it, that's the shale. It's an impervious formation and where the oil is contained, that's porous sandstone, so the oilbutts up against that shale and it cannot move and it forms a trap there. Okay, next slide, Harry. This is what we call a strategraphic trap where you see the formations are the sandstone containing the oil. You lose that as you go over to your right and you just have the two shales laying one on top of the other and it forms a trap for the oil. The oil cannot migrate any further. Now, in Prudhoe Bay, we have something -- Mother Nature is usually not that simple. There's always a combination of things that occurs in the ground and the Prudhoe Bay field, the north boundary of the main pool in the unit is a fault boundary and over to the east, we have something similar to this where the sand is bumping up against an uncomformity and the sand doesn't exist as you go further east so it

forms a trap, kind of a stratigraphic trap, in that direction Next slide. This will give you some idea of how wells are completed and what we do to evaluate the formation, to isolate the formation, to stimulate the wells if the productivity isn't high enough and what production equipment we install on the wells. Next slide. When a hole is drilled under the ground before you complete the well, you want to try to find out what the formations contain and one of the tools for doing this is running your well logging tools down the well bore and they're usually on a wire line with the electrical read-out at the surface and there's various logging tools that you use to determine various reservoir parameters, but this just gives you an example of what you do once you get the hole drilled in the ground before you do anything else. Once you've looked at your well logs and you've established that there is a zone of interest in the ground; in this case the dark zone there indicates a potential oil zone, and with shale above and below that oil zone to contain the oil, you may want to run a test in your well. In this case, it shows a drill stem test which is a test tool run down on your drill pipe. You set a packer in the hole above the oil zone, then you open your tool up to the atmosphere and let any fluids flow into the well that will and that way you determine what the potential of that well is before you run any casing or complete your well.

Once you've established that you do have something in your well, often you will then run your casing, which is steel pipe, down to the bottom of your interval of interest, you pump cement down the pipe and up around the outside of the casing to cement that to the formation so you'll have a good seal and you'll isolate that oil zone from any of the surrounding formations and the cement used in this operation is an oil-quality cement that has to withstand high temperatures. It's a special-type cement. Next slide. Once you have your casings cemented in the well, then you have to have some means of allowing the oil to flow into your well bore. In this case, you see a jet perforating gun has been lowered in the hole and you actually shoot holes through the steel casing and the cement sheath around that casing with high velocity gas which comes out of your jet perforating guns and establishes communication into your oil zone and oil is allowed to flow into the well bore, then, under a control situation. In this case, this is probably a tight formation like the previous core from pemana (ph) I showed you there. The well would not produce naturally so you go in and you hydraulically frac that well by pumping at high rates and high pressures to break the formation down, make it crack, and then establish a better communication in your well bore or improve your permeability, as we say. Next slide. Once you have found oil and you have

completed your well, if it's a flowing-type well like many we have in Alaska, like the ones we have in the Prudhoe Bay field, this is a typical valving setup that you have on the wellhead itself and it is commonly referred to as the Christmas tree. It's just a combination of various valves to flow the well in different ways. Next slide. Now, in the South 48, you'll often see a lot of pumping units like this. This is where the wells are not capable of flowing. They need some assistance and you have to actually pump the fluid out of the ground. You don't see these up in Alaska. There's many reasons but the environment is one and then the platforms in the inlet, they don't lend themselves to big pumping units and a lot of the wells are flowing up here and they use other means of lifting the oil up here. Okay, we'll get into how oil is produced and the first is what we call primary production. This shows a displacement process down in the reservoir. In this case, you have water moving in through the reservoir which is indicated by the blue color and it displaces the oil ahead of it and this can be a natural displacement--something that if you have have an active aquifer , the water may move in naturally and later on we'll see how you can introduce water in the ground under a secondary or a recovery program or water injection. Next slide. This shows that same portion of the reservoir where the water has now gone

AGO 532124

through that portion of the reservoir and displaced all of the oil that it can. You see oil left in there--the little black spots. They're in between the sand grains and that oil is what we call residual oil. It cannot be recovered with known technology today and that is why we say in many of the fields we leave 60% or more of the oil behind and this shows you how it's left in there. Just in little small globules. They're not connected together. The oil has no flowing phase any more. Next slide. This shows you some of the natural energy forces of water and gas expansion and how they displace oil. Here, in this case, this is a natural water drive taking place and you see the oil in the anticline being produced from the wells completed in the oil leg and the water underlays the oil and it presses against the oil and pushes against it and actually flows through the reservoir like the other slide showed and pushing the oil into the well bore. That's one form of energy that you might have in the reservoir helping you out. This is what we call a dissolved gas drive. There is no water in this case aiding you with any reservoir energy. The energy here is coming from the gas dissolved in the oil. It's very similar to an excelsior bottle where you have a straw running down into the bottle. If you open that straw to the atmosphere, the carbon dioxide dissolved in the water will force the fluid out of the bottle, and this is a

similar type of mechanism for dissolved gas drive.

BY: MR. MILES

In a previous slide, you showed water coming up. What displaces the water as the water rises as the oil is brought out?

BY: MR. HAMILTON

The water expands. As you lower the pressure in your reservoir, you've got a large aquifer and it will actually -- the water will expand and move in there.

UNIDENTIFIED SPEAKER:

The water has a head on it?

BY: MR. HAMILTON

Sometimes it can have a head and other times it can be just pure expansion if the aquifer is large enough. Even though water doesn't have much of an expansion factor, if it's large enough, it can be a considerable amount of energy push on that oil. This is a gas cap drive mechanism where we have a gas cap overlaying the oil and this slide and the previous one are essentially what we have at Prudhoe Bay. We have a gas cap overlaying the oil column and water underneath the oil column. And, in this case, as you produce the oil from the well bore, the gas cap expands. It has energy there that will help you push that oil into the well bore. In the case of Prudhoe Bay field, we're taking the gas as it's produced, reinjecting it into the gas cap to

maintain the gas cap pressure. Now, we'll get into some improved recovery by fluid injection processes. In this case, this is one type of a water flood that you might have where if the energy isn't sufficient in the ground to recover the oil you'd like under, say, primary mechanism, and usually you can improve on that by some other -- by introducing energy into the reservoir. In this case, it's water. This would be considered some type of a pattern flood where you're injecting water in water injection wells with offsetting oil producers and you hope to establish some type of a front to push that oil ahead of you into the oil well, then. It's very important that you do get your wells placed -- injection wells placed properly in the reservoir so you do establish a front. If you don't establish a proper front, you can lose a considerable amount of oil in this type of a process. Next slide, please. This is another form of you might say secondary recovery--gas injection. Although you don't see too much of this--it's not as efficient as some of the others--if you have a gas cap, you normally return the gas to the gas cap, but here it just shows injecting the gas into the oil column itself. Well, that's a very, very brief rundown of what -- some of the mechanisms that take place in the reservoir, and before I turn it over to Joe Green for his part of the presentation, I would just like to talk briefly about the Prudhoe Bay

field. Mr. Chairman, you mentioned earlier just how large and complex that reservoir is. Just for the enlightenment of everyone here and some people that might not be aware, the productive area of the Prudhoe Bay field covers roughly seven townships, and if you're not familiar with the size of a township, you could reduce that to square miles and that's roughly 250 square miles the field covers, or 160,000 acres, roughly. We're talking about a formation that's -- in that productive area -- that's 450 feet thick, and I've used this illustration before, but I think it's a pretty good one. It's twice the height of the Anchorage Westward Hotel in Anchorage, so you've got something that covers 250 squares miles, is 450 feet thick and it's quite a large reservoir to model. In order to attempt this, we've gone to a 3-D model that contains approximately 7600 grids or cells, if you might want to call them that. It's a mathematical model and each one of these cells more or less would represent a cubic city block or something of that nature. Now, we tried to describe that reservoir, the fluid parameters and everything that has to go into describing that city cubic block, and each one of these 7600 grids. These various parameters that we put in there to make this description are -- 23 or so that are used for each one of these cells. Once you get your model put together and all these parameters described in each one

of these cells, then you try to produce that reservoir and if you have some production history like we do now at Prudhoe, try to match your model to that production history to make sure the production from each well, the pressures from each well, are identical to what you have observed in that reservoir. Now, in order to do this, we so far have analyzed over 400 different pressure surveys in the field and that's all I'll say. I'll turn it over to Mr. Green who will give you his presentation on some of the work we've done, but I just want to impress with you the enormous size of this modeling chore.

BY: MR. MILES

Thank you very much, Mr. Hamilton. Really a good presentation. Mr. Chatterton?

BY: MR. CHATTERTON

Thank you, Mr. Chairman. Commissioner Hamilton, you mentioned the 250 square miles. That's like you're up in the satellite looking down on it with the plan view and the 450 feet thickness. Now, first of all, talking about the aerial extent, the plan view, you gave some slides there that showed these sand grains and everything and you spoke of porosity and you spoke of permeability. Now, do you find that the petrophysics say, in one corner of this 250 square miles is the same as it is in the opposite corner or what happens? Is it all the same or.....

BY: MR. HAMILTON

It certainly is not the same. It's not the same aerially or it's not the same vertically. I mentioned before, Mother Nature does not provide us with things very often that are nice and uniform and homogeneous. It's a heterogeneous reservoir and it not only changes -- the sand characteristics change but we also have layers of shale throughout the reservoir and they change aerially and vertically also.

BY: MR. CHATTERTON

Now, these cores that you get from these wells, how big are they?

BY: MR. HAMILTON

They can be various sizes, but they may be five inches in diameter, six inches, four inches, depending on the size of the core barrel they run in the well.

BY: MR. CHATTERTON

And these few cores, why, from that you have to analyze what the whole 250 square miles looks like or predict and you also have to figure out just exactly what it is from the top of the zone to the bottom of the zone?

BY: MR. HAMTILTON

That's right. We'll.....

BY: MR. CHATTERTON

And nature makes it different, is that right?

BY: MR. HAMILTON

That's right. We use the core data along with our logging evaluation work plus our testing work plus our pressure survey work. All these things are tied together to try to evaluate this large hunk of reservoir rock. That's true.

BY: MR. CHATTERTON

Thank you. Thank you, Mr. Chairman.

BY: MR. MILES

How many core samples do you take out of a grid?

BY: MR. HAMILTON

There is no particular requirement. It's just whenever you feel that you can get a -- or you need some more material, and, normally, they just core the vertical holes, and like the first well drilled in Prudhoe on a pad, either the first or the second, or one of the first wells, there's usually a vertical hole, and many of those vertical holes have been cored, and the reason they core the vertical ones, you have a better control over your depth where the sample came from and you're penetrating the formation vertically and not at an angle so you get a better sampling of the formation, but I think we have somewhere in the neighborhood of -- I'm off the top of my head -- something like 11,000 feet of core from the reservoir itself that's been taken up there in Prudhoe Bay.

BY: MR. MILES

When you say 11,000 feet of core, what does that refer to? I guess I don't know what..... What's the dimension of a core? It's four or five inches across?

BY: MR. HAMILTON

Say the zone is 400 and some odd feet thick. That's equivalent to coring that 400 feet many many times in different portions of the reservoir. You take this five or six inch diameter core through that portion of the reservoir and pull it up to the surface and analyze and, as I say, we've got about 11,000 vertical feet or so of those cores that have been taken from the wells.

BY: MR. MILES

Thank you. Mr. Hayes?

BY: MR. HAYES

Yes, Mr. Hamilton, I failed to write down how many cells or grids you said -- you take this 200 plus square miles and you break it up into grids from which you prepare a computer model?

BY: MR. HAMILTON

Right. That's right.

BY: MR. HAYES

How many grids was that, roughly?

BY: MR. HAMILTON

Well, Dr. van Poollen is going to talk on that. I used a rough number of about 7600, now.

AGO 532132

BY: MR. HAYES

7600.....

BY: MR. HAMILTON

Grids. Now, is that.....

BY: DR. VAN POOLLEN

That's the total number of nodes. We have about 4600 active nodes.

BY: MR. HAYES

The question I was going to ask is when you say we, who is we? Is that -- when you say we, we have computer models or we have made certain determinations. Who is we? Is this the State of Alaska or is this the State of Alaska plus the oil companies, or how does..... Who is we?

BY: MR. HAMILTON

Well, the model itself is owned by Dr. van Poollen and the people that are working on this particular model study is our staff, primarily Joe Green in the engineering phase of it with Dr. van Poollen's staff. We also have our geologic staff who help develop the geology that goes into the model, and we've also met with the operators to discuss these various parameters with them before we model them.

BY: MR. HAYES

But, I -- if I might continue, Mr. Knight, I assume, then, that the oil companies are also concurrently developing the same type information?

BY: MR. HAMILTON

Yes, that's true.

BY: MR. HAYES

And the information that -- one of the pieces of information that's being developed is, I think has been discussed recently, is what the -- how much oil can be recovered from each one of these grids or cells and then averaging that all out together, how much the field is going to yield in terms of -- what is the percentage of recovery of original oil in place or something like that?

BY: MR. HAMILTON

Um-hum.

BY: MR. HAYES

Is that what we're talking about?

BY: MR. HAMILTON

That's what we're looking forward to trying to determine, yes. We've made, you know, our preliminary work. You may have seen those reports and what we came up with before the field was under production and now we're doing it again with some production history.

BY: MR. HAYES

Okay. So, the oil companies are coming up with one -- they're coming up with information or estimates on the percentage of recovery and the State independently is coming up with an estimate of percentage of recovery?

BY: MR. HAMILTON

That's right.

BY: MR. HAYES

And are you getting together and checking results?

BY: MR. HAMILTON

We will when we get through with our work, and they have already indicated that their results haven't changed from their initial studies. We don't know if ours will or not until we.....

BY: MR. HAYES

Have they made their studies available to you--their computer printout of their computer models and the results?

BY: MR. HAMILTON

When we had our hearing prior to the startup of the field in order to set conservation order 145, they presented results of their runs, yes, at that time.

BY: MR. HAYES

But you didn't verify the results against the computer runs. I mean the.....

BY: MR. HAMILTON

We didn't get the computer output, no. We just got the production volumes and the results from the computer output, yes.

BY: MR. MILES

Joe?

BY: MR. GREEN

Thank you, Mr. Chairman. I will try and keep my comments very brief and hopefully in layman's language, but as Hoyle indicated, if there are questions, please feel free to ask. A brief history which goes along with the recent questioning would be that in '74 there was a volumetric study performed with the old Division of Oil and Gas, predecessor to our Commission, and Dr. van Poollen. There were subsequent update studies of '75 and '77. These were two-dimensional computer -- three-phase, two-dimensional simulators -- and from those, it was hoped to determine whether or not gas sales would create a problem with ultimate recovery. The conclusions from some 39 runs that were published in those studies was that no appreciable loss in production would occur from limited gas sales.

BY: MR. MILES

Limited.....

BY: MR. GREEN

Limited to the amounts that were given in the studies.

BY: MR. MILES

We're talking about two billion cubic feet, is that.....

BY: MR. GREEN

Yes, right. They ran, as you may or may not be aware, they ran some runs with no gas sales, some with limited gas sales, some with water in flux, some with -- in various

production scenarios. The problem, of course, with a two-dimensional study.....

BY: MR. MILES

Excuse me, Mr. Green. Mr. Chatterton?

BY: MR. CHATTERTON

Thank you, Mr. Chairman. Mr. Green, was there not a caveat to what you said, no appreciable deal, and was there not a caveat to it made by the old Division of Oil and Gas that there would be simultaneous full-scale water injection?

BY: MR. GREEN

It was a recommendation that there be water injection pressure supplement but these, like I say, were various cases--some with, some without, and, yes, there was a pressure drop, an appreciable pressure drop without water injection, and there were variations in the production. In some modes, there was a greater difference than others, but the general conclusions were that with pressure maintenance or with some -- and in this case, the water injection did not start immediately, it started at some subsequent date. There was essentially no difference. Certainly, within the accuracy of the model, the recoveries were similar.

BY: MR. CHATTERTON

Thank you. Thank you, Mr. Chairman.

BY: MR. GREEN

And that is, of course, one of the problems with a two-

dimensional model, instead of looking at the whole cake, you're looking at a slice of the cake, and, well, this has some advantages of cost and simplicity. It has the disadvantage that you don't see the total reservoir or portions of reservoirs as we will hope to convey to you that Prudhoe, because of its magnitude, is not -- while it is a common reservoir, it's like several reservoirs. There are portions -- a question was asked about the recovery per block. At the present time, it looks like there may be a considerable variation in the recoveries per block. A block, perhaps, that's in a section that doesn't have problems with shale, doesn't have tight streaks in it, has good vertical permeability has good gas saturation potential, the recoveries could be quite high, conversely, and some portions that are shaley -- and I'm not necessarily talking about the large shales, but laminate -- a thin, poker-chip type, if you will, playing-card type shales, the recoveries will probably be less, and so this is one of the beautiful things about a three-dimensional study that you can actually find these various things out that you couldn't by a two-dimensional, but because of the work that the--and I'm going to use the word Conservation Commission, if you don't mind, because that's what we are now. This actually was the old Division of Oil and Gas, but the work that was done from the studies that Dr. van Poollen and the Conservation Commission did, together

with the testimony that was given by the operators, a conservation order No. 145 was issued and an interim order was given as the operating rules in effectively a two-year basis. It was thought at that time, after a two-year production history, more data would be gained and hopefully a three-dimensional study would be completed, and at that time there would be a review to see if those orders still stood or there should be a revision. Suffice it to say that there were 15 special field rules for Prudhoe of which eight of them.....

BY: MR. MILES

Excuse me. You say that was two years. The order was June 1, '77?

BY: MR. GREEN

Yes.

BY: MR. MILES

So, we're at August, '79. What's the status of the update work?

BY: MR. GREEN

What is the what?

BY: MR. MILES

The status of the update. You said conservation order 145 was a two-year order, so what are you doing now to either update it, change it or come out with conservation order 146?

BY: MR. GREEN

We're running a three-dimensional computer study and when the results of these are in, we will take a look at those and compare those with the results of the two-dimensional studies before. If there is a significant -- if there is a difference that would create any kind of problem, there will be another hearing.

BY: MR. MILES

So we're essentially on hold until the next one.

BY: MR. GREEN

Yes.

BY: MR. MILES

Until Dr. van Poollen's work is completed.

BY: MR. GREEN

Yes.

BY: MR. HAMILTON

Mr. Chairman, I may add, that two-year period is not built in the conservation order 145. This is just something we were working toward--getting some work done in a two-year period to review it to see if it was necessary to rewrite another conservation order.

BY: MR. MILES

Mr. Rogers?

BY: Mr. Rogers

So conservation order 145 is in effect until you adopt a new one?

BY: MR. GREEN

Yes, that's correct. Some of the -- without referring to all 15 special rules of that order -- some of the items that are germane to this hearing, rule two was well spacing. No well would be closer than 1,000 feet to a boundary line or within 2,000 feet to another well bore which effectively comes up with 160 acre spacing. That's not quite, but it's effectively that. Rule six had to do with pressure surveys that there would be static pressure surveys on all new wells, one key well per pad, each 90 days all wells would have transient pressure surveys within six months, there would be a semi-annual pressure survey per section and that a long-term key well program would be established. Rule number seven that there would be gas-oil ratio tests, initially between 90 and 120 days and semi-annually thereafter on all wells. Rule number eight had to do with venting or flaring and that's only as allowed by the Commission. Rule number nine, gas-oil contact monitoring. You may refer -- the slides that indicated Prudhoe Bay has a large gas cap and to monitor the location of the gas-oil contact, special logs are run at completion of the well and periodically through the well's life and we have had excellent results with the particular log that shows any movement of the gas-oil contact. Rule number ten has to do with the water-oil

contact monitoring. There are several logs being determined -- looked at there to determine if there is water-oil movement and, of course, one of the main things there would be fluid entry surveys that when you get water and the fact that you are getting water. Rule eleven has to do with production profiles. We periodically will run a production profile. You will recall the slide that shows the fluid entering the well bore. There is a tool that is run at that point and shows not only where the fluid is entering but the type of fluid that's entering--gas or water or oil or both or all three, and rule fifteen which has to do with off-take rates that were established field-wide of 1.5 million barrels a day plus condensate and 2.7 billion cubic feet of gas a day.

BY: MR. MILES

Mr. Chatterton?

BY: MR. CHATTERTON

If I may interrupt. Thank you, Mr. Chairman. Mr. Green, I will ask this question of you. You may wish to ask one of your leaders to reply to it, but do you feel that the Commission has the manpower needed to adequately monitor whether the rules set out in conservation order 145 are being carried out and analyze them if they are being carried out? How do you feel? Have they been carried out?

BY: MR. GREEN

Yes, I feel they have been carried out to the letter. We

have had exceptional cooperation. We do review monthly not only pressure surv- -s as required, spinner surveys, fluid entry surveys, if you will, all of the various requirements by the operating order are reviewed. We do have a limited staff but with the advent of the computer, we are able to keep, I feel, on top of this.

BY: MR. CHATTERTON

Thank you. Thank you, Mr. Chairman.

BY: MR. MILES

The question of water flooding is obviously one that we are going to be discussing at great length. Does the Conservation Commission have the authority to mandate water flooding in the field?

BY: MR. GREEN

If there would be, by our analysis, ultimate waste of the reservoir, yes.

BY: MR. MILES

That means reduced recovery and ultimate waste means reduced recovery of oil, so you can order that?

BY: MR. GREEN

Yes.

BY: MR. MILES

I see. Mr. Hayes?

BY: MR. HAYES

Mr. Green, did your preliminary studies show greater ultimate

recovery at lower rates of production than the 1.5 billion per day that you mentioned previously or did you.....

BY: MR. GREEN

There was essentially no difference. There was some indication that there may be rate sensitivity, but within the ranges that we looked at, there wasn't any. We are going to look at that. With the model we're looking at now, certainly rate sensitivity would be one of the key riddles that we're looking at.

BY: MR. HAYES

Did you say what range you.....

BY: MR. GREEN

The prior study was between 1.2 and I believe 1.8.

BY: MR. HAYES

Between 1.2 and 1.8?

BY: MR. GREEN

Yes.

BY: MR. MILES

Mr. Chatterton?

BY: MR. CHATTER

On that point, Mr. Green, if my memory serves me, actually some of those prior studies show that there was an actual increase in the percentage of oil -- original oil in place produced as the daily rate went up.

BY: MR. GREEN

There were some results that would indicate that. I, perhaps, might turn that over to Hoyle and Hank since they ran those.

BY: MR. HAMILTON

Yeah, there were some where -- the gas sales cases, as I recall, where we dropped the rate down below 1.5 to the next rate that we looked at and we actually had a slight reduction in ultimate reserves and where there were no gas sales, I think the lower rate had slightly more reserves, but some of these variations are fairly slight and we're going to take another look at those, but you have to be careful when the variations are just slight whether or not you are kidding yourself in a long-range prediction like we're making and they are essentially the same if they're just slight, but we will look at that again, yes.

BY: MR. MILES

Can I get a clarification on that so I understand what you're saying? Some runs showed increased recovery, some showed decreased recovery. Is that, in essence, what you're saying?

BY: MR. HAMILTON

Yes, some showed considerable decreases depending on what you did but.....

BY: MR. MILES

Depending on the factors that you plugged in.

BY: MR. HAMILTON

Right.

BY: MR. MILES

I see.

BY: MR. HAMILTON

What I'm saying is if you get a slight decrease or a slight increase in comparing these runs that the accuracy of running a prediction mode for the entire life of the field there is a range there where you -- this fluctuation range where I think you, by and large, can almost call the thing the same with the accuracy of the results, but we'll probably go through this qualifying process when we get the results of our 3-D model and when we explain the results of those runs.

BY: MR. MILES

Mr. Malone?

BY: MR. MALONE

Thank you, Mr. Chairman. Maybe this question is better deferred until we get into the discussion of the reservoir study itself but is there any way of making a judgement as to the -- statistically -- as to the accuracy of a model in advance of the production that's going to occur. In other words, you have an idea as to how -- statistically -- how accurate a model is before the year or two years goes by and you compare production with the model itself. Is there some way that you can get an idea that it's probably accurate within ten percent or twenty percent or something

like that so that you know whether or not the variations are significant?

BY: MR. HAMILTON

Dr. van Poollen, who I'm sure can talk upon this -- he's probably better qualified to answer than I am, but the model work I've done, if you get a production history match and take that same period of time and forecast in the future say one or two times that time period, you can do that with a fair decree of confidence. You start getting beyond that and your degree of competence from that model starts stirring quite a bit and..... Would you like to address that problem?

BY: DR. VAN POOLLEN

Yeah, I've made a general statement, not just about this reservoir, but I feel that you cannot with any degree of accuracy really predict more than two years the life of the field and then thereafter your certainty goes way down. A lot of things could happen. For example, you didn't have a chance to fully evaluate the aquifer during that period The aquifer may start coming in at a later time, so you didn't have a chance to match all these. So, on the other hand, you might say, well, what did you do at the time that you didn't have any history? Well, you're creating your own crystal ball. You're predicting the best you can. So, now we have seen that Hoyle and I did a study. We published

that in '76 and we subsequently published an appendix. We're coming up with certain sets of numbers. We find that other groups have done similar work independently such as the operators, other consultants. They all take a slightly different look at how they build the model. When I say building the model, you don't -- aren't changing the mathematics. It's all the same thing, but define the parameters that you put into the model. So, independent sources all come up with about the same kind of numbers and they agree with one another. Then you start getting some confidence. Now, the next thing is, is to what extent now that we have some history, can we actually check how accurate the previous work has been. So, how close are you tracking and I don't know whether you want to comment on it now or whether you want to wait until later when we -- I don't know if you want to go through all these questions, Mr. Chairman, or.....

BY: MR. MALONE

Perhaps the question can be elaborated on when the discussion of the reservoir model itself is elaborated on. Keep in mind that -- I don't need any further answer right now, but my question really was, you say if you develop a 2-D model based on certain information, you must have an idea in mind that it's accurate within certain limits. I mean, some statistical rules to apply to it and maybe a deeper discussion of that would be better put off until a little

later on.

BY: MR. GREEN

Well, you might think of it this way, Hugh. If we knew exactly what the reservoir contained, if we knew, for example, it was a tray of marbles, or it was just like that core that we looked at, we could predict precisely when, how much and the whole nine yards, if you will. The problem that Hoyle mentioned earlier is that we can't tell, if you were to take a city like Anchorage, and that represents the reservoir, and you have a core that happens to come down through the middle of the Anchorage Westward and then a half a mile away you happen to go through a baseball park and another half a mile in another direction and then you say, okay, I can tell you now what Anchorage looks like from a few of these cores, you can begin to see the problem. So, we say, alright, it must be an average and therefore we apply those averages and start to run, we know what the wells actually did. That's a historical fact. We've had a year and a half's history. We know exactly, so we make the wells perform the way they actually did. Then we go back and we look at -- well, alright, in order to get that, did the saturations, did the pressures, did all these things actually work out the way our reservoir measurements say? Well, in this case, they did but over here, they didn't, so we have to modify these parameters

a little bit, and it's a massaging, if you will, until the values that we're using, the average values that we're using for the reservoir, make the reservoir perform the way it actually did, and that's why the longer the history, of course, the better your prediction, because you can massage those things down to where they're probably a lot closer to reality.

BY: MR. MILES

Mr. Chatterton?

BY: MR. CHATTERTON

Just for my clarification, now, when the history doesn't fit and you've got to false it, you use what is known as a psuedofunction?

BY: MR. GREEN

That's right.

BY: DR. VAN POOLLEN

No, no. I don't want to agree with that.

BY: MR. CHATTERTON

That's not right.

BY: DR. VAN POOLLEN

The psuedofunctions is a mathematical trickery to take a city block and do all your calculations on one city block where in reality you're dealing with millions and millions of little pore spaces, so that's where the reason -- psuedofunctions comes in. It's just a mathematical

trickery that you have to do because you're dealing with such huge blocks.

BY: MR. CHATTERTON

But it's trying, if you use it, to make the model fit the history.

BY: MR. HAMILTON

Yeah. Other things you change, other parameters. If you're not getting pressure into that particular zone, and you should be getting pressure based on your history of the pressure from that well, then if you've got an overlaying shale, you have to provide some permeability through that shale or some way for the pressure to get there since that's, in the real world, that's what you measured in the well, so -- and sometimes you have to change the permeability around the well to make it flow and maintain a certain pressure to match the thing, so there are parameters you have to change down there.

BY: MR. GREEN

The relative permeability of one fluid in another phase. There are some 20 different parameters at each little grid that he's talking about has to have and each one's a tiny little material balance at each time and each of those change and so the computer has to go through and calculate each one of those by each time step and it gets to be a very complex situation.

BY: MR. CHATTERTON

Thank you. Thank you, Mr. Chairman.

BY: MR. GREEN

Carrying on, then, the -- I was -- indicated that we would have a small gathering and so the exhibits that I have are meant to hand across a table and I apologize for that, but I will perhaps hold these up, try and point out to you and then pass them around for your inspection, if that's alright. I think they're too small to put on the wall and show. This is a performance curve of Prudhoe Bay and I've color-coded them. The black is the oil production. The orange color, if you will, is the gas production. The purple is a gas-oil ratio. There's a number down here, the number of wells, and this tiny little line down here is water production, and might pass that around just to show what we're doing now. The gas-oil ratio as you will notice--that's that purple curve--is, ah..... After the field established a more or less -- established a rate of approximately a million to a million and two-tenths barrels a day, the gas-oil ratio went to approximately the solution ratio and the last four or five months has gradually begun to increase. This is certainly understandable. We expected that to happen. As pressure decreases, the gas-oil ratio will increase. This is just a phenomenon of the reservoir. We are monitoring, as I said, the -- not only the

gas-oil ratio by wells and by intervals of wells but also the gas-oil contact, and we have a typical map -- this just shows the end result rather than the actual contours, but we contour gas production, water cuts, various things, on a semi-annual basis, then compare that also with bottomal pressure surveys. This delineates certain areas that may not be acting as the average. It shows areas, if you will, that may be anomalous and I'll pass that around. It's somewhat awkward, but red indicates just for diagramatic purposes shows wells that are currently making gas-oil ratios in excess of 1,000, solution being somewhere around 700. The blue line indicates wells that have indicated from a trace up to a few percentage of water cut, so there is water movement and there is gas movement down from the gas cap. By the way, for your own edification, you'll see a little cluster of wells and then a large void and then the major number of wells. That's the gas cap area. Those clusters are gas reinjuction wells. Some 90 percent of the gas that's produced is reinjected into the reservoir. And, as I say, this is to be expected. How, there have been a couple of wells that the gas-oil ratio has gone up, in one case, up to six or seven thousand. Another one is around four thousand. Most of them though, in that red area, are down a thousand, fifteen hundred, and, as I say, nothing to be alarmed about because we anticipated that.

We have, in effect, in that area, three different kinds of gas, if you will. We have a gas fingering coming out of the gas cap following a shale. We have a secondary gas cap. Then we have perhaps a small gas coning. That might sound alarming at first blush, but it isn't. Part of that occurred approximately six or eight months ago when the rates were higher than they have been since then. Flow station three in that area has been put on production. The per well rates have been reduced and, in most of the cases, the gas-oil ratio has stabilized--in some cases, actually gone down again. The interesting thing is that in that area, the average pressure for, say, the ARCO side of the field, is slightly higher than the average pressure for the SOHIO side.

BY: MR. MILES

How much is slightly higher?

BY: MR. GREEN

Approximately 20-25 pounds. I mean, they're very close. The ARCO side had gone down a little. They've since -- stabilized actually, as a little higher.

BY: MR. MILES

Mr. Chatterton?

BY: MR. CHATTERTON

Thank you, Mr. Chairman. Mr. Green, I'm going to ask this question in an oversimplified nature just to try and open up a point, if it's any rationale to it. This map that you're

passing around, it's a two-dimensional system and you've drawn some red lines on there to show where there's been excursions of gas in some form or another. Now, you didn't testify to this but is it not true that some of these wells that you've drawn this red line around do not necessarily expose--in fact, some indeed do not expose--the same lithologic equivalency in the third dimension?

BY: MR. MILES

What does that mean?

BY: MR. GREEN

I think maybe we have something here that might help.

BY: MR. MILES

We're asking these guys to speak in easily understandable language. At least the Committee members could do the same.

BY: MR. CHATTERTON

Okay, he's going to have a demonstration here. I'm sorry. I withdraw the question, Mr. Chairman. Thank you. I'm trying to show you need the third dimension.

BY: MR. GREEN

This is a cross section, in effect, a geological cross section through a portion of the reservoir, through the oil column. It's an east-west cross section. It's not complete but it's enough to show, I hope, what I'm trying to show. This section is about this much longer in that direction. But, you see, we come into what they call the truncation interval

and if anybody is not familiar with it, this is an erosion of the surface that forms a barrier to the east side of the reservoir. There's a shale, if you will. Remember the example that Hoyle used in the slide where the reservoir came up and it was called a pinch-out? In effect, that's what you've got--an erosional surface called an unconformity and a shale body lying along the top of it. It happens to actually be the theoretical source of the oil migration, but that's not our purpose here today. The major reservoirs that we have--the Pute River sand which is a stream bed, a very, very limited and extended -- traces just like an old river bed. The Sag River Shubley Complex which lies just above the Sadlerochit. This is not a structural section, that is, these wells are not aligned as they truly are, but since they're almost along a common structure line--in other words, they follow almost -- without trying to mess the works up, here is a structure map that shows where the section is and these lines are equal sub-sea elevation, these heavy lines. This section is a red line running along here so, for a good portion of it, until you hit this truncation surface, that's where this begins to cut down through the reservoir. It is almost on strike, if you will. It's not exactly but it's not intended. What we're trying to show here is a correlation section, so we've hung all these wells at the top of the Sadlerochit at the top of the sand interval, the major reser-

voir that we're exposing. The blue, as you will notice in here, there's a lot of blue in certain areas. The blue represents shales. In some cases you'll see it's corable from one well to another and not over here. Here's one that's corable but not over here. Here's one that's corable for about six wells and then stops. Here's one. As you come down through this, and for purposes of our own use, we have arbitrarily divided the reservoir into thirds, upper, middle and lower, for lack of a better name, and that's primarily because of geological differences. This reservoir is slightly different than this portion of the reservoir which is slightly different from this portion of the reservoir, both in permeability and porosity and in shale content. As you can see, this midsection is a conglomeritic zone with very little -- there's only -- in this particular section, there's only a couple of very insignificant shales in that whole area. Conversely, when you get into the lower section, and especially over on the east side, you see abundant shales and corable, or, in other words, that looks to be connected from one well to another. That makes a considerable difference, then, for example, to try and have one of the drive mechanisms, gravity drainage, to go from here to here. You couldn't get that from down here if your perforations were down here and, low and behold, in this particular section, most of the perforations are down here. There's a considerable amount of this

reservoir, then, that is not presently perforated and several of the wells could not possibly produce as the wells are now completed. Now, there's a very good reason why that's the case. We mentioned earlier the gas coning, the water coning. The operators have perforated judiciously what they call a stand off--a distance away from a water-oil contact, a distance away from a gas-oil contact--so that as the zone produces and there is a gradual lowering; for example, the gas-oil contact is moving about an average of about 20 to 25 feet a year, moving down. If they had perforated up near the top of the interval, gas-oil contact here, and they had perforated the zone up close to that, in a few years, they would have gas coming in. The well would gas out. The gas-oil ratio would become prohibitive and they'd have to either go in and do remedial work, squeeze, shut the oil in, or one thing and another, whereas the way they have produced it, they can produce the wells a quite a bit longer time before they have to either go in and recomplete the wells, add additional zones, various optimization methods of ultimately getting the oil out of the reservoir, but I hope this is what you are indicating, that there are several wells, in fact, no well -- I take that back. There are a few wells over near the truncation where the reservoir is the thinnest, that effectively expose the entire reservoir that's there. I don't believe there's any well where we have the full reservoir --

there is no well that has the entire or total reservoir perforated. The reason that passionate pink is used on the Shubley, by the way, is that is not a sand. It's kind of a roots, guts and feathers formation. It's got a little bit of everything in it and, at the present time, insufficient knowledge about just -- there is oil and gas in it, but it's not a major reservoir, but we wanted to differentiate it from the shales in blue and the sands in yellow.

BY: MR. MILES

Mr. Chatterton?

BY: MR. CHATTERTON

Thank you. My point, Mr. Chairman, and my very bad question.....

BY: MR. MILES

I presume it was an excellent question.

BY: .....is to point out that all runs that the State has made so far is using two-dimensional models and I tried to point out to you there is a third dimension. It makes a difference.

BY: MR. GREEN

Does anybody want to see this? It just shows where a section was -- a typical section map. It happens to be a contour on the top. It has a blue outline of the water-oil contact and the gas-oil contact. We indicated earlier that there is an order to monitor pressures and, to date, all wells are -- there's a static pressure build-up prior to production and transient pressure

surveys periodically after that. These surveys are used for a couple of very important reasons; one, to monitor the regular pressure but, and I think this is an extremely important point; right now, the only pressure that we can monitor in a well is that portion of the well that's perforated. What I'm saying is then that if a well is only exposing a fraction of the reservoir and we run a pressure survey on it six months or a year after it's been on production, we can't tell what the reservoir pressure is for the entire interval that that well exposes but only that portion of the well that is in pressure communication with those perforations. If there is a sealing shale halfway up the reservoir, then the rest of that reservoir, unless produced at some other well, is still at virgin pressure.

BY: MR. MILES

What would block your various testings of the pressure besides a shale formation? Sheer distance?

BY: MR. GREEN

That would be one although if the permeability is good enough in this reservoir that if it were just distance, eventually you would reach it, and the well spacing is such that we would be able to reach..... We have essentially pressure stabilization within one day, which is quite good. The permeability then is.....

BY: MR. MILES

Of the entire reservoir?

BY: MR. GREEEN

No, no, no, no. I mean from a well. You actually reach essentially reservoir -- or the pressure at some point out there where it either starts to be influenced by the next well or it actually reaches static pressure within one year. See, the pressure, when you first shut it in around the producing well is quite reduced. It may be several hundred pounds lower than reservoir pressure, so you shut the oil in and the reservoir pressure builds quite rapidly, then. The faster it builds and stabilizes, the better the permeability, if you will. If it takes a long, long time to build up, then you've probably got, like that pemena core that Hoyle showed, very, very tight. Whereas, at Prudhoe, we get a very rapid pressure build-up indicating a high permeability and there's a mathematical calculation. You can determine what the permeability is.

BY: MR. MILES

Is that similar to water seeking it's own level--pressure seeking to stabilize itself, or am I just on a completely wrong track?

BY: MR. GREEN

Let me put it this way. If you had a great, huge apartment building, that apartment building would represent the reservoir and all the rooms in there as the porosity, and if you only

had one or two windows and doors in there and people were trying to get out, they'd have a heck of a time. It has a high porosity but a very, very low permeability. You can't get the people to move. But if all the doors would suddenly open--you had patio doors everywhere, then the people could move out very quickly. You'd have high permeability. And what you're doing, then, is trying to get from this pressure reduction in the well bore out to something that represents the reservoir pressure, and the bigger the amount of doors for that building, the quicker you get there. That may be rather juvenile, but if you understand it, that's the main concept and that's what our purpose is here.

BY: MR. MILES

That's what some people have called this Committee.

BY: MR. GREEN

Well, if you'll excuse me, I'll go look for work. We, of course, with the recommendation that some sort of pressure maintenance would be advisable, and water being probably the most readily available since there isn't another gas field the size of Prudhoe that we could use to supplement the gas, one of the main objects would be, then, to determine what kind of profile, what kind of injectivity we could establish in the reservoir, in various portions of the reservoir, but certainly within this vertical variation that we've got. We have a statistical variation in permeability, the horizontal

permeability that we're measuring. Some parts of it have, as I mentioned, few doors and some parts have quite a few doors, and if you had a well that was open to all of those and you put water in, obviously, you would go where the more doors were and not very much go where there's very few doors. If you allow the reservoir to be operated that way, you're going to leave an awful lot of oil in the ground because you just didn't sweep the oil from the portion that had very few doors and windows in it. When you have a bad permeability variation--in other words, some extremely high and some extremely poor permeability--you have a bad permeability variation and, unfortunately, we have quite a variety of permeabilities in Prudhoe, so one of the things that we have to determine is the injectivity and the profile that we can expect if we ever start water flooding. There are two injectivity tests. One has been completed and one is currently under way, and this is an effort to, as I say, find the injectivity, find, if you will, the amount of sweep efficiency. What sort of coverage are you getting in the reservoir when you push water in. To date, we can put water readily in the aquifer, we found out. We can put water readily into the oil van. We can't put water readily in the tar mat, and I don't know whether you people are familiar with this term, tar mat, or heavy oil mat that exists at the water-oil contact. It's a lower gravity, higher viscosity oil approximately fourteen gravity or so that varies

in thickness but is approximately 25 or 30 feet thick on the average. It goes to 80 and as low -- in fact, in some places, may not even be. It may not be a continuous mat, but this thing would act as a retardant to natural water encroachment. It's not a complete barrier. There is some movement through it, but it's not as mobile as the oil -- the live oil above it. The three-dimensional study that we are doing now, the Conservation Commission was aware that it would be a good idea beccause, from a monitoring standpoint, it's a jewel to see just how the reservoir is reacting and is it reacting exactly as you planned the field, various things like that. The problem is, as Dr. van Poollen pointed out, if you try and do this too quickly without any kind of a production history, you don't know how to modify the averages which is what you are dealing with, that you need, so one of the difficulties that we are having is, it would be nice to have ten years of history in the first 18 months. There is no way you can do that, of course, and so it's going to continue to be an updating thing. We can make as close a prediction as we can make now. We'll have to review this and I would imagine that periodically we'll have to update it and perhaps even change somewhat, but Dr. van Poollen will get into that in a lot more detail. I have here -- I've got some show-and-tell things that..... This is an example of the sweep configurations that you get. Now, this happens to be a five-

spot pattern, referred to in the industry -- four injection wells and a central producing well somewhat like the figure five on the di or domino, and I've taken one quarter of that to show what is a typical -- now this doesn't refer to Prudhoe or any other particular reservoir. It's strictly schematic, but it shows the aerial sweep on the left and the only reason that I've only gone to one quarter, if you make this symetrical, it looks like some sort of a doiley and that is distracting, so, if you will, the shaded area represents that portion that at the time you get watering out of the central producing well is the amount of oil that you've swept leaving that white portion in between the lines. On the right hand side, you have the vertical section and this is because, as Chat asked, and we tried to indicate with the cross section, you have a variety of permeabilities throughout the reservoir and, as you can see, then, the water would go through the high streaks much faster than it would through the low permeability streaks. Again, reaching across to the producing well, watering the well out or going to a prohibitive water-oil ratio, without ultimately sweeping all the oil. Now, these are calculated risks that you have any time you conduct a water flood program. The problem is you want to try and maintain that -- minimize that, if you will, and that's where we are right now with injectivity tests, with permeability tests, with additional development. We're getting a much better handle. We have a

better handle now, for example, on the shales--where they are, where they're continuous. Instead of just projecting them, we can see them.

BY: MR. MILES

When you say we, who are you talking about?

BY: MR. GREEN

The Conservation Commission and van Poollen.

BY: MR. MILES

And through van Poollen, so to speak?

BY: MR. GREEN

Yes.

BY: MR. MILES

Has the industry made similar tests?

BY: MR. GREEN

Oh, yes.

BY: MR. MILES

And how did you interact with them? Do you get that information or some of it or none of it or all of it or.....

BY: MR. GREEN

What we do, our approach is to take the information that we have and make our independent evaluation and then to review with the industry engineering committee to say this is where we are and this is what we've got. Do you see anything that we have that is not reasonable, not -- we've had a couple of situations where we weren't in complete

agreeement but, by and large, they say, yes, that's.... Actually, I have to admit that the industry is ahead of us. I don't think that comes as any great secret. They have already completed several different production scenarios with three-dimensional, three-phase simulators and we're kind of playing catch-up.

BY: MR. MILES

Are the results as you play catch-up pretty close to the results that industry indicates it has?

BY: MR. GREEN

I honestly can't say at this time, because we're just not that far along, but the similarity between the two dimensional, ours as opposed to theirs, we're in very close agreement. I don't see anything now to say that our three-dimensional won't be similarly synonymous or close to theirs.

BY: MR. MILES

That's good to hear. Mr. Parr?

BY: MR. PARR

Yes, Mr. Green, the show-and-tell as you called it that you passed around, am I correct in thinking that when it comes to injecting the water, you can choose where you inject the water both in the horizontal plane and also the depth to which the water is injected?

BY: MR. GREEN

That's correct.

BY: MR. PARR

Okay, so if you didn't want to have happen what happened in your vertical section here, you simply would not have that water go out of the column at that point, right? It would only go out further down or on a different level, is that correct?

BY: MR. GREEN

Yes, now, if you were to take this idealized vertical section and not want, for example, water to go into that top member because that's gone clear across, or you want to restrict the water in there, you could do so if you were fortunate enough to have one of those continuous shales that we talked about that are fairly prevalent in the lower zone as we -- the lower one third of the reservoir. You could complete below that and not have too much fear of that water migrating up into a high perm streak that might be in the middle zone because you have that barrier that extends out into the reservoir. But if you didn't have that and you took corrective measures at the injection well, you could squeeze cement, you could use prelimeric (ph) water gels, you can use a myriad of treatments at the injection well or at the producing well, but those treatments are of a limited nature. You go out a certain distance, but there's a practical limit to how far you can push those things. Eventually, the water would seek around that corrective measure and go back into the high perm

streak and that's one of the problems with so many water flood projects is that they just cannot control the high perm or the fracture in some cases, the extremely high permeability streak.

BY: MR. MILES

Mr. Parr?

BY: MR. PARR

One more question. Looking at it from the industry's standpoint, are there cost factors involved which would make industry prefer to inject the water only, say, in shallow depths, down in that bottom third, or is that a consideration?

BY: MR. GREEN

Yes, but I think far, far overweighing the cost consideration would be what industry or what the Conservation Commission felt would be the most efficient method of production?

BY: MR. PARR

I said the industry viewpoint. I didn't say the Conservation Commission viewpoint.

BY: MR. GREEN

Okay. Well, I think they're synonymous in this case, though. Even if industry were going to do it, I think they would be concerned about the cost, certainly, but if, for example, they could put water in the lower third because they've got the shales to keep it confined where they want it, and in the middle zone where there wasn't shale, preferred to have gravity drainage, I think that would overweigh what they

might consider about having the dual injector, so ....

BY: MR. PARR

Well, what I'm thinking about, obviously, is you approach the point where you may be having a net negative balance on your water injection, right?

BY: MR. GREEN

Um-hum.

BY: MR. PARR

Obviously, at the beginning, perhaps there's no question, you're getting back three dollars for every one you put in but at some point you must start approaching a break-even ratio or a negative balance and that was the reason for my question about this.

BY: MR. GREEN

Oh, I see. Well, I think there will, certainly. Economics will have a very direct bearing on this, but I was trying to get across to you the fact that while economics is one factor, ultimate recovery is the main factor and that generally overshadows, certainly for several years.

BY: MR. MILES

Mr. Hayes?

BY: MR. HAYES

Mr. Green, you mentioned that industry was way ahead of the State inasmuch as they've apparently completed both their two and three dimensional work and the State is -- at this

time finished their two dimensional and are expecting soon to get the results of the three dimensional. At this time, based on the information that you have, do you agree with the industry figure of 40 percent recovery from the original oil in place? Do you agree with that figure?

BY: MR. GREEN

I may get shot for this but I can't actually say. I honestly am not trying to evade your question. My gut reaction, if you will, is that it probably won't be quite 40 percent. It will probably be over 35 percent, but I wouldn't go to the bank with a figure like that because that's truly a gut reaction from some limited cross section work, from -- well, just from what I've observed, but I'll be able to answer that question a whole lot better in a month.

BY: MR. HAYES

I could follow up on that. You're probably familiar with a letter I recently wrote to Mr. Hamlin asking him about what I thought was a discrepancy, or at least something that raised a question about a 65 percent recovery factor that was in one of the federal documents that -- based on some testimony or supplemental transmittals were made and then the 40 percent industry statement and I raised the question about which was which. When were you first aware of the 65 percent figure or how long ago have you been aware of that?

BY: MR. GREEN

As a recovery figure for a gas-invaded gravity drainage reservoir?

BY: MR. HAYES

Well, for whatever.

BY: MR. GREEN

Or specifically at Prudhoe?

BY: MR. HAYES

At Prudhoe. I mean, when were you first aware of that 65 percent figure in the publication 95-73? How long ago?

BY: MR. GREEN

Oh, probably a month or six weeks ago.

BY: MR. HAYES

Okay, which is, I presume, why Mr. Schmedley (ph) in a recent letter to you was pointing out to you what that meant.

BY: MR. GREEN

Yes, well, the reason I asked Larry to write the letter was that, by looking at the information on the page that the graph that you are referring to or the table was shown, it doesn't designate that that's just for a limited portion of the reservoir. You could take that as the entire reservoir.

BY: MR. HAYES

That's the way I took it. That's why I asked that question.

BY: MR. GREEN

Yes, and so I asked him, all right, since that was an Exxon statement, would he issue a statement corroborating what most

of us would realize that, that is a special case and it does only apply to a portion of the reservoir.

BY: MR. MILES

What portion?

BY: MR. GREEN

The gravity drainage portion without the -- the vertical barriers -- the shales, where you can have high gas invasion, of course gravity is working for you there. Gravity wants to keep the gas away from the oil and so you'll get a much higher recovery there than you would say, if you were having to lift high water volumes. Gas-oil ratio we're going to -- maybe as much as twenty-five thousand and water-oil ratios maybe three to one. So its just a problem when you're lifting from two miles away of -- how much can you afford to lift.

BY: MR. HAYES

Could I just (indisc) . Just a couple more -- I assume you're satisfied with that explanation from Mr. Schmedley?

BY: MR. GREEN

Oh yes.

BY: MR. HAYES

And I presume.....

BY: MR. GREEN

Yes, gravity drainage is not uncommon.

BY: MR. HAYES

Yes.

BY: MR. GREEN

And high recoveries from gravity drainage fields are not uncommon. But, they require specific, specialized reservoirs to do it.

BY: MR. HAYES

But, okay, but -- you still haven't seen the -- again you're only working with their final figures. When they say forty percent and they say 65, but you haven't seen, they don't give you the computer backup on it?

BY: MR. GREEN

No, I think where that would come to play is if -- if for example the two dimensional results. If the commissions results were half or only a third or something like that of industry, then yes, we would say lets -- we got to go to the map. If they're in quite close agreement, then there really doesn't seem to be purpose served and if our three dimensional figures come up with a grossly different or -- I mean if instead of something pushing 35 to 40 percent, if they come up with 20 percent, yes, we would want to got the mat again.

BY: MR. HAMILTON

In that same document you're referring to, I don't know if you received a copy of my letter I sent you.

BY: MR. GREEN

No, not yet.

BY: MR. HAMILTON

I mailed it the day following our -- the letter I received from you, but we'll find the same thing true in our model. There'll be areas of the reservoir, you're going to have a higher recovery in other areas. In order to get a, say a 35 percent recovery or 40 percent overall recovery, you're going to have areas with 60 percent recovery and some areas with 30 percent, some with 20 percent. Over a few pages from where you took that 65 percent recovery, they stated what they felt the overall recovery was -- was 40 percent for the entire field and there was a little misunderstanding there, what the 65 represented. But it just represented that portion -- just portions of the reservoir.

BY: MR. LOWENFEL

Right. Let me supplement for a second how we would get the back up information should it become necessary. Obviously, if the commission decides to hold a hearing and as a result of that hearing, decides to order water injection -- and the oil companies took exception to that, it would be incumbent upon them to come forward and demonstrate what their figures were and how they obtained those figures. We want that to be part of the record.

BY: MR. MILES

Okay.

BY: MR. MILES

Joe, is that it?

BY: MR. HAYES

Yes.

BY: MR. MILES

Mr. Chatterton?

BY: MR. CHATTERTON

Thank you, Mr. Chairman. If you grant me the laditude, I want to take a slight excursion here. Mr. Green, you for some months now have worked intimately with Prudhoe Bay and its reservoir performance?

BY: MR. GREEN

Yes, sir.

BY: MR. CHATTERTON

You have also been intimately involved with the three dimensional modeling of the reservoir?

BY: MR. GREEN

Yes, sir.

BY: MR. CHATTERTON

You probably are closer to this picture than any other person in State government?

BY: MR. GREEN

I would -- would presume that it right.

BY: MR. CHATTERTON

PAGES
64 & 65
ARE MISSING.
nfn

stopped, but we may do it a little differently. Other than that, I think we've been in extremely close agreement. As I say, the nice thing about it is, we do it our way and then ask them if they agree with it.

BY: MR. MALONE

(Indisc)

BY: MR. GREEN

Yes.

BY: MR. PARR

Mr. Hayes, do you have a question?

BY: MR. HAYES

One final question in regard to the question that I raised a few days ago about -- about the 65 percent and the 40 percent and some of the information that was submitted to Senator Jackson's committee. I have a copy of a letter dated October 31, 1977, to Senator Jackson from Mr. Kuntz of Exxon, and he states in part -- in part of his letter, "the owners have purposely designed a plan, which provides flexibility to respond to observed performance and we are confident that gas sales of two billion cubic feet per day commencing upon completion of a gas transmission system will not adversely affect ultimate oil recovery from the field". Do you agree with that statement?

BY: MR. GREEN

I have really no choice but to agree with it now because of

what the prior computer analysis. Again, I would like to hedge, if you will, for a month, I'll have a whole lot better handle in a month.

BY: MR. HAYES

Well, perhaps in a month you could let me know.

BY: MR. GREEN

Alright, sir. Yes, I would be glad to. Well, that brings us around to our beginning a three phase three dimensional. We took, if you will, some slices of the cake, some two dimensional cross sections and that's in a sense about as -- the best comparison I could make, that you got this cake and you take a slice out of it and you got a bunch of candles respresenting the wells and you say, okay, how does that thing actually react? With the wells that we got, you got a much less expensive method of just taking a look at it, arriving at parameters that we hope to use then in our full three dimensional, because if you can imagine a model as large as Prudhoe knowing that there's going to have to be some massaging in just trial and error. That's seven to ten thousand dollars a run. You could run up a tremendous bill bef .e you begin to get the same values that you can get closer to with cross sections. And if you will, this is a north-south computer section, one of the three that we used. (WHEREUPON TAPE CHANGED) These here are the wells in this particular cross section and these are the completion intervals as they are

in which grid blocks are exposed in those wells and if you can see, there are some red lines in here, those indicate the corable shales. As you can see, these first two wells only expose grid blocks 17 and 18 of a full 18 grid block section. Of course, from 15 down or 15 up rather, in this particular (indisc) is all gas. Here it goes to 13 and here it goes to about 8 or so. Anyway, what my point is, we said each of these wells have a production history. We forced the computer to take those production histories and then we observe what the saturation and pressure changes were in all the grid blocks around there. We did see, in some cases, gas moving down, in this one particularly, we found gas coming down this way. At the conclusion of this cross section. Well, let me go back one step, we had as we lamented only eighteen months of history to try and match. What we wanted to do, was to find out what we had to do to the permeabilities, the relative perms, the viscosity of the -- you know, all these various parameters that go into making up a reservoir flow model in each of these little grids to make these wells produce what they did and the saturations and pressures be what they really are in the reservoir by buildups. When we finally got that for a history match of eighteen months, we said alright now these grids are too small to be transposed into a -- our three dimensional grid, because we were fifteen times as fine in this cross section, as we would be in our

3-D computer model. So, we wanted -- the finer we could get, naturally, you see this -- how this contact is a series of straight lines instead of a nice smooth line. This is the thing you get into. If we could have had a billion cross sections or little grids, we probably would have been closer. It would have taken us several hundred years in order to run that, but, so there's some optimum point. We felt this was somewhere near an optimum point. We have to go from this then to a coarser grid to get it on a three dimensional, because if we had a thousand on this, we would end up with something in the neighborhood of thirty or forty thousand grid blocks with twenty different parameters and we just don't have a computer that will handle that. So we had to make them bigger and rather than take just a short production history again to make the big blocks equal the little blocks, we said, alright, let's run the little blocks out to something. Let's have a -- base run, just so we can have some numbers to try and match to and that's what we did. We ran that up and then we could come along and see what we had to do to the bigger blocks, to make them equal the little blocks and then we felt we could go to the 3-D computer model. Well the problem occurred though that when we did that, there was an awful lot of oil down here that wasn't produced. There was no wells to produce it from. So, inadvertently, the number got out that there was only 21.9 percent recovery

from Prudhoe Bay, which was a fallacy, because we didn't recomplete these wells. We had extremely high rates. One well here at twenty thousand barrels a day to the time it stopped producing because the gas-oil ratio of only ten thousand to one, which is too low a gas-oil ratio to condemn it. It produced out and then just stopped. Well, no well produces like that. That wasn't the point. What we wanted was a -- calibration that we could match to. So anyway, because there was a tremendous amount of oil down here, then just as an experimental run we put a couple of injection wells in, we put a few more producing wells in, then, of course, the recoveries shot way up well over 30%, and so -- and even then we still oil -- free oil bank, but all we wanted to do then was to just justify to ourselves sure enough that there was -- you could get an awful lot more recovery than we had on this -- this first run. And, without going into anymore of the detail..ah..we can go into how we determine the process in water saturation, if you want to, but I'll leave that as a question because I don't want to bore you with any of that detail and a lot of this stuff Dr. vanPoollen will get into when he talks about the three-dimensional study.

BY: MR. MILES

I see, thank you Joe, I know that -- did a lot of homework to get ready for this and we really appreciate it. Questions

for the Conservation Committee? Mr. McKinnon.

BY: MR. McKINNON

Ah..your going to ..ah.. a great deal of record to determine what should happen to the reservoir from here on out, what did the Commission do to determine the initial rates of production that..ah..the companies began with, 1.2. What's magic about 1.2 million barrels a day?

BY: MR. GREEN

I might defer that to the people who ran the model, if you don't mind.

BY: MR. HAMILTON

The procedure we follow and we do this with any reservoirs. We don't set a rate until we see what the operators want to produce that reservoir at. They come to us with an operating plan, their operating plan. They ask for 1.5 million barrels a day offtake rate for a while and 2.7 billion cubic feet a day for gas, then we -- we were working with our model studies at that time, we ran those rates through our model studies varied rates on either side of that and it looked like, at that time, based on those model studies, that was a pretty good rate to operate that reservoir at and then we put those rates in our conservation order 145 as limitations and with the caveat, as we mentioned before, changing those as we -- as we see fit if we get new data indicate that they should be changed.

BY: MR. McKINNON

Well, the illustrates that I've seem in Mr. vanPoollen's ..ah.. studies are that 1.2 figure have you examined anything lower than that?

BY: MR. HAMILTON

We did not and if you'll notice..ah.. the waterflood cases there with a gas sales the rate was dropping off slightly or the recovery was dropping off slightly as you drop the rate back down, so we didn't go below the 1.2.

BY: MR. McKINNON

The studies show that the rate of -- that ultimate recoverability drops as you decrease..ah....

BY: MR. HAMILTON

Yes, that's what it showed for gas sales cases, yes.

BY: MR. McKINNON

Oh, with gas sales. How about without gas sales?

BY: MR. HAMILTON

Without gas sales it was about the same 1.2 to 1.5, actually the 1.2 had a slightly higher recovery.

BY: MR. McKINNON

But you didn't do any runs lower than 1.2?

BY: MR. HAMILTON

No, we did not.

BY: MR. McKINNON

Is there any particular reason for not doing it -- runs

lower than 1.2?

BY: MR. HAMILTON

Well, as I said, we -- we assumed at that time there was going to be a gas sales line, now, there may not be..ah.. your guess is as good as mine. Now, we will do some more runs this time and we'll probably run some at lower rates, but with the gas sales line it indicated that if you went anywhere below the 1.5 toward the 1.2, you were actually getting less recovery.

BY: MR. GREEN

That's what I said, even -- you know -- the rate of change was probably within the degree of actual of the two-dimensional model. So, there wasn't any reason since we had to have a history, a production history, to match to the three-dimensiona study anyway, it didn't seem to be any problem and that will be borne out, we can -- we will, in fact, plan to run some cases with variable rates, variable times with water, I mean, a more complete gammut, but we've got a bigger model to do it with.

BY: MR. McKINNON

I'd..ah..heard internally there was some problems with gas coning..ah.. in the field. What -- exacting what is that and how does it effect....

BY: MR. MILES

Can I ask a follow up question before you, sort of, change

subject. What -- you indicated that there would be slightly higher recoverability at 1.2, can you quantify that?

BY: MR. GREEN

Well, this is the thing I tried to dwell on before. There..ah.. with no gas sales returning all the gas to the gas cap and with some water injection..ah.. the 1.2 showed a -- a higher recovery than the 1.5 under those conditions, but very slight I mean, there wasn't much difference. With gas sales, with large scale water injection, the 1.2 rate actually had a lower ultimate recovery and..ah..but these are very close to the other recoveries -- it doesn't indicate it's that rate sensitive, but this time we will probably run an array of rates again just to verify that.

BY: MR. MILES

Go ahead Joe.

BY: MR. McKINNON

Alright, we'll stay with that line of questioning. If -- if your studies do show that the 1.2..ah..figure does ultimately recover more than 1.5..ah..is it likely that your order would then restrict production to the 1.2?

BY: MR. GREEN

If we have substantial evidence, yes, that we need to cut back on the rate to improve recovery we'll write another conservation order, yes.

BY: MR. McKINNON

How significant a difference between the two rates of production

would there have to be for you to a....

BY: MR. GREEN

Well, it's not just the significance in the two rates, it's the significance in the recovery itself and also..ah..what we feel the accuracy of our predicitons are, we're going to have to give it a pretty hard look when I go through this thing and just how much history we need to really verify that -- that within a certain range these numbers aren't all the -- essentially the same, at this point in time, as far as recovery goes. And I think this borders on what Jeff indicated that..ah..we come up with something, say 3 or 4% points difference, that's pretty significant. I think we would ask the operators to come forward and show us why they feel that this is not a valid thing and then we'd get into the mat, we'd find out what assumptions they made versus what we'd made. Where did we deviate from the data that we all used as a common data base and why. Is there a difference in their model than ours? I think that's when you get into a real hair pulling session.

BY: MR. McKINNON

Okay, what..ah..what is coning and what does it indicate?

BY: MR. GREEN

If you could visualize a big rubber diaphragm with a string tied to it, representing the well, and you started to pull down on that, could you visualize what that -- what that

diaphragm would look like. That would be the gas off contact starting coning on the well. It would be a conical configuration moving down toward the pressure drop. See what happens, you've got a pressure here and a lower pressure..... Okay. Go ahead. Diagram.

BY: MR. HAMILTON:

Here's the gas-oil contact, for instance. This is a well bore. We perforate that well, say, in this interval here. Say we produce that well at a certain rate and it produces essentially all oil with whatever solution gas is in the oil. Say we increase that rate several fold. We can increase it to the point if these perforations are too close to that gas-oil contact, you'll actually pull that gas-oil contact down like this, and, in turn, this will be gas in here instead of oil and your well will go to a very high gas-oil ratio. That's what we call coning. If your perforations are too close to the gas-oil contact or if you're pulling too hard on a well, you can cone the gas down in the well. Now, there's various remedial measures you can do once you establish coning. If you're fortunate, you can cut back on your rate somewhat and you can heal the coning and the contact will possibly go back up like that and you won't produce free gas down in your well. Or you can complete the well lower down and squeeze off these perfs with cement and then you'll get back into -- you get your oil production again with a low

gas-oil ratio, but that, essentially, is what coning is for gas. Now, the reverse is true for water. If you've got a water -- oil-water contact down here, and you have perforations that are close to the oil-water contact with a high enough rate, you cone the water up in your well bore the same way.

BY: MR. GREEN

Remember I mentioned earlier that there was only a portion of the well that was completed, a stand-off, if you will? In this diagram, the perforations are some 250 feet below the gas-oil contact and 100 to 150 feet above the water-oil contact. But you add those up and, of course, you've got more suction than you have, and the answer is that this is a tilted thing, and so, as you get up toward the gas-oil contact, you don't have the water. That's down here so that you can stay above the water and stay below the gas. And as this pressure drop that causes the coning is dissipated, then when you have that much stand off, that's dissipated out and the total thing comes down this way rather than this way.

BY: MR. HAMILTON

I think Dr. van Poollen has a better example. You stick a straw in a milk shake, just barely stick it in, and take a healthy draw on it and you will start sucking in air. You push the straw further down in that milkshake and you'll draw the milkshake down without pulling in air. That is coning

of air when you cone that air down that straw.

BY: MR. McKINNON

Well, how much of a problem has it been in Prudhoe Bay?

BY: MR. HAMILTON

It's been very little problem so far up there. Just -- we dwelled on the area out in the east. Joe can review that again but.....

BY: MR. GREEN

There are some 20 wells that are involved in ratios above normal and of those, about a third of those are attributable to tonguing. If this is an impermeable layer, gas can come in and migrate down that impermeable layer to a well. In a similar fashion, at least for the same reason, a pressure drop, if you will -- here's high pressure and low pressure -- about a third of them are involved in coning and about a third of them are involved in secondary gas cap. In other words, the gas is coming out of solution and forming a secondary gas cap. Now, those numbers will -- but it's about a third, third, third. Now, the operators can -- I think the plan is that they are going to go through in quite a bit of detail the performance so we purposely glossed over that so there wouldn't be a redundancy.

BY: MR. MILES

Mr. Chatterton?

BY: MR. CHATTERTON

I'm on your same subject, I think, okay? Mr. Green, you mentioned earlier on pressure surveys where you have a well producing and you shut the well in and -- with a pressure recording device at the bottom of the well -- at the end of the first hour, for example, I think you said the pressure could be quite a bit lower (indisc., coughing) end of 24 hours, it would have built up to basically static pressure. That's a healing process. Then you used the term healing when you were talking about gas coning. In other words, it is a reversible action, is that what you are trying to tell me?

BY: MR. GREEN

Yes, generally that's the case. If you create a sustained high gas ratio and continue to deplete the oil in a small interval, a cone or a finger, to where the gas saturation far exceeds the oil saturation, it might take some time to heal because you've trapped the gas there and it's more than will go readily back into solution. But when you talk about a situation like that, we're talking, I think, three or four wells out of over 200. This is important from several standpoints, one of which is to see what effect it does have on a reservoir to do it in an area where you have a limited amount of reservoir and it's in an area that you can go in -- in fact, almost undoubtedly will go in with water because

it happens to be there -- that shaley interval where you can control it, then you can heal it that way, but it's a good thing to learn how to handle that much gas, for one thing, and is it a healing thing? Some reservoirs -- if it were truly marbles, as the example, if the reservoir truly were marbles, it would heal instantly, but, unfortunately, it's not marbles. It's something tighter than that.

BY: MR. CHATTERTON

Thank you. Thank you, Mr. Chairman.

BY: MR. MILES

If you're having coning, can you lessen the effect if you have more wells in an area and just had all the wells producing at a lower rate. Would that take care of the problem?

BY: MR. GREEN

Yes, that would help.

BY: MR. MILES

Is that the kind of thing that the Conservation Commission might do if that became a problem?

BY: MR. GREEN

That would be one thing. The other might be just as Hoyle said, the rate itself, rather than say you've got to drill more wells. You might have to reduce the rate or rate per well type of thing. Not necessarily the rate, the field.

BY: MR. MILES

Other questions for Mr. Green? Gentlemen, thank you very

much. It's almost 5:30. I think now would be a good time to take a brief dinner break. Dr. van Poollen, would 7:00 this evening be acceptable to you? I won't ask everybody else.

BY: DR. VAN POOLLEN

No problem.

BY: MR. MILES

Okay, we'll reconvene and once again, gentlemen, thank you very, very much.

(OFF RECORD)

(ON RECORD)

BY: MR. MILES

We'll reconvene the meeting of the House Resources Committee. Unfortunately, a number of interested persons and Committee members are in State Affairs Committee up in Finance Committee so we don't have our full complement, but it's important we move ahead with the work and so, with little introduction, Dr. van Poollen. I had previously sent you a number of items that we requested you touch on in the course of your presentation. Those items have been distributed to Committee members so, I guess, just take it away, if you would, please.

BY: MR. HAMILTON

Mr. Chairman, for just one moment, if you wouldn't mind, you've also addressed six questions to the Commission before you get through with us, and I prepared written responses

AGO 532193

to those questions and I think we've already covered most of those in our presentation. Instead of just reiterating them over again, I will pass out our written responses to those, if that's alright.

BY: MR. MILES

That would be great. That would be super. With that, Dr. van Poollen.

BY: DR. VAN POOLLEN

Thank you. I didn't make a formal written speech. What I thought I'd do is first reiterate how we got involved in all this modeling and give you a little bit of a history. As early as 1972, we've been involved, that is, we, our company has been involved with the State through the Oil and Gas Division in trying to study the reservoir. Initially, we have looked at the volumetrics and we have worked very closely together with the Commission and then, subsequent to that, we prepared a study, a reservoir model study, keeping just the overall reservoir parameters in mind. Now, throughout these studies, we had meetings with operators to check that our parameters that we were using were in line with the parameters that they were using, not the other way around. I mean, we showed them what we were using and they said, well, that looks just about right, or sometimes they might find a little flaw in it. Then I could go back to my -- do my homework a little bit more, but, in general, it's all

AGO 532194

our own data that went into it. For example, we have some different interpretations on relative permeability curves. We have somewhat different volumetrics. We're not using their numbers. We're using their basic data. We're using our own numbers throughout, so in 1976, I believe it was, we published a report on several computer runs that we had performed using a relatively course grid type of a reservoir model. That particular model had only in the order of 120 grid blocks in it, which is tremendously more coarse than the one we're talking about now, more like a magnitude of 40 difference. After we had these runs and let them digest in our mind, we came to the conclusion that some of them were not necessarily realistic because you actually ended up with very high reservoir pressures which you would never do in a field like this by overinjecting. So, we came out with a supplement which is dated February of '77 in which we attempted to keep the reservoir pressures approximately the same at the end of the depletion period, and I dare say that those particular runs are somewhat more realistic than the ones we had before. Otherwise, I guess we would have made them and published them again. However, the conclusions in general were about the same relative to the possibility of gas sales, relative to the possibilities of water injection and relative to the overall field rate. We were criticized at the time that we didn't have enough information on no gas sales and consequently

Dr. Doscher, who is here, performed another study which used the same model we had and this was not truly published. I gave it to him and he in turn wrote a report for the Legislature in about June of 1978, and all of these runs are essentially based on the same model, the 120 grid block, very coarse grid model. One of the first questions that you are asking in your letter is how does the field perform today as compared to any of our predictions? Well, it's held up very well. As a matter of fact, at this moment, the reservoir pressure in the field is approximately 10 pounds higher than we would have forecasted as a withdrawal based on those studies and that, in itself, is very encouraging. Nevertheless, it was felt that a more detailed study should be made prior to entering into a major decision on pipeline support and things of that nature. A 3-D model was selected. It was originally recommended by Dr. Doscher. We ourselves agreed with this. At the same time, we realized all the time that this is a tremendous undertaking to do a three-dimensional model.

BY: MR. MILES

Dr. van Poollen, if I can interrupt. Did I understand you to say that the pressure in the Prudhoe Reservoir is generally ten pounds higher today.....

BY: DR. VAN POOLLEN

Than we would have predicted for the same amount of withdrawal out of the field, yes, sir.

BY: MR. MILES

.....than you would have predicted, but it's -- is it higher or lower than it was when we started and by what different degrees?

BY: DR. VAN POOLLEN

All right. I'll have to look at my graph to get you the exact number. At this moment, the reservoir pressure is 171 pounds lower than it was when we started, so when I say at this moment, that is after a withdrawal of 633 million barrels. That is what I call this moment. I don't have any data beyond that myself that I can make that calculation, so I made the calculation at 633 and right now I believe the total withdrawal is 743 so at 633 million barrels withdrawal we observe a field pressure drop of 171 pounds and the model would have predicted 181 pounds.

BY: MR. MILES

I see. Can I interpret then from your testimony that you would have predicted a pressure at 10 pounds higher that -- should the State have anything to worry about, generally speaking? Is this.....

BY: DR. VAN POOLLEN

I would have predicted it ten pounds lower than what it really had.

BY: MR. MILES

Lower, yes, yes.

BY: DR. VAN POOLLEN

Well, I think that's pretty close, you know, 171, 181. That's a very close approximation. If anything, it behaved somewhat better than our forecasts were up until this time.

BY: MR. MILES

Okay. Thank you.

BY: DR. VAN POOLLEN

Now, why is a question I cannot answer precisely, but I will pose the question myself anyway. Maybe the aquifer is a little bit more active than we had anticipated, or maybe there is some more energy coming from somewhere else that is connected to the reservoir that we have not anticipated. But, all in all, for a reservoir study after you have withdrawn on the order of 10 percent of the recoverable oil to get this kind of a match I think is pretty good.

BY: MR. MILES

Mr. Chatterton?

BY: MR. CHATTERTON

Doctor -- and I agree, ten pounds out of 170 is not too damn much. Five percent or something like that. But would you also get the same deal if there was more original oil in place that is pressure connected than was originally anticipated?

BY: DR. VAN POOLLEN

Entirely correct, and it could be there is an additional energy source that we had not modeled in. Now, the energy as

Hoyle Hamilton was showing earlier might come from a water drive. We have always felt that the water drive would not be too overly affected, but it could also come because there might be more oil or there might be more gas connected to this particular reservoir, but I think -- I don't want to go on record and say I anticipate there is more oil in Prudhoe Bay than we ever thought there was. I would say that there is no reason to be afraid of the pressures that we see in the light of what we published earlier.

BY: MR. CHATTERTON

Thank you.

BY: MR. MILES

I think you can please continue, sir.

BY: DR. VAN POOLLEN

So, to continue with the idea of the 3-D model, we all realized that this would be a terrific amount of work to do this and if anywhere I am concerned, it is that somebody is going to ask me the question, how come you're so late in performing your study? I don't have a good answer for that other than it's a terrific job, and it's been our philosophy that if we're going into this kind of a detail, that we might as well put in the best possible data we can and I prefer, myself, whether this is right or wrong, to have the right data in there and get the right answer and be somewhat slow than to come up with the wrong conclusion. Nevertheless, at the

same time that we're doing all this, we are getting a better feel for the reservoir and we certainly are in an excellent position to have a model available that will be able to be used as a monitoring tool for the entire reservoir. We will be able to monitor the gas-oil ratio behavior and the water-oil ratio behavior and one of the things that has been scaring us the most is the uncertainty in our minds on what do all these shales do to us? Are they important or are they not important? Are they going to decrease the gravity drain and if they do that, will they in turn then reduce the recovery of the field? On the other hand, if they are there, will they be advantageous at the time of water flooding and by knowing where they are and getting a better and better handle on this, we are monitoring the field with this kind of a model. The operators, if they are doing it, and I know they are doing it, but the State can pass better judgment on whether or not a certain injection scheme is justified or not. And I'm kind of jumping the gun a little bit on some of the questions and maybe not taking them in sequence, but, for example, if you start water injection in the very, very beginning, there is always the chance that you're injecting it in the wrong place, that you are consequently forcing the oil up into the gas cap and that would be the worst thing you could ever do and consequently knowing how these shale breaks behave is a very important issue. Now, through the work that we have done

today, which is not the full 3-D model as yet, however, the cross sectional work that Joe Green was showing you a graph of is showing us that these shale breaks are not 100% barriers, namely, if we tried to match in that fine grid section, which I believe -- what was it -- a thousand eighty grid points -- if we assigned a zero permeability into the shale breaks, we cannot possibly match our pressures in that particular cross section, in that pie cut, in that section of the field. We definitely have to have permeability in it. Now, whether that is, scientifically speaking, that the shale itself leaks or that the shale is discontinuous and has holes in it and some time during this meeting, maybe tomorrow, you will hear the expression windows; I mean, it's just holes in the shale. We definitely feel that these shales must leak and that in itself is a very important part of this study. We're getting a much better and better reservoir description as we are going. To do the 3-D model study, we are talking about computer runs that are costing in the order of, well, between $5,000 and $12,000 per run, which is an astronomical number and it's kind of freightening to push the button in the morning and then in the afternoon find out that you have the wrong cart somewhere. It's bad enough if you know it's a true boo-boo. You can kind of write that on experience, but if you stick something in that you didn't -- that you kind of overlooked, then it's kind of criminal, so we are spending a terrific amount of time.

I'm trying to get the reservoir description in it. Now, I'd like to say something relative to how we are conducting this study and what we have done as far as relationships with other organizations. First of all, our company has approximately six people working on it all the time and we meet very frequently and are basically in daily contact with the people in Anchorage, with Hoyle Hamilton and Joe Green, and discuss our progress and keep ourselves up to date on that. Then, in addition to that, Dr. Doscher visits with us on the average, let's say, once or twice -- well, every one or two months or somewhere in that order, and reviews with us our progress on a general basis and has been able to make various valuable suggestions to us or I have been using him as a sounding board in trying to find a short-cut and I could name you several of these but sometimes you say, well, don't you think we're just kind of up in a dead alley? Yes, you're in a dead alley, so why don't you go on? And that's been very fruitful to us and then from time to time, we meet with the operators to discuss basic data and also to get a few little hints from time to time. They have been working on this for a number of years where if I say that we have half a dozen people working on it, I don't know exactly their number, but they must have a terrificly large number of people working on it, and, oh, the little mathematical tricks that you sometimes might want to do that are

unrelated to the final outcome of the reservoir itself, but for example, when we are evaluating the pressure build-up curves, that is, after you shut the well in, the pressure starts to rise and will eventually end up with a static pressure and those are the static pressures that we would be using to see whether the field is matching against the mathematical models and consequently you get a better forecast, but also the rate at which this particular pressure is rising when you shut the well in is an indication of what's going on in the reservoir relative to the permeability and the shale breaks.

BY: MR. MILES

Static pressure. Can you explain that term? Is that just the stabilizing of the pressure or a maximum point?

BY: DR. VAN POOLLEN

Yes, if you shut a well in and, let us just for simplicity, say after a day or two days, that well is back to equalibrium. That pressure reduction around the well bore has disappeared. The pressure service has equalized, so static pressure, equalized pressure, reservoir pressure, these are all the same thing. One of the problems in the oil business, we have many names because we've got people coming from different disciplines and they all want to invent new names, but there are many names for the same thing.

BY: MR. MILES

Thank you.

BY: DR. VAN POOLLEN

So we had meetings with the operators and presented to them our method, how we did it, what kind of numbers we came up with. We never saw their numbers, but -- and they never saw a complete list of our numbers unless Joe Green sent them to them, but we just kind of made a few checks. Hey, what have you got for this? Well, yeah, that's about the same, and so on, in that order of magnitude. The same thing we have done relative to the relative permeability curves, and the relative permeability curves are probablly the crux of this reservoir or -- this reservoir -- any reservoir and any prediction. If you have 50 percent oil saturation and 50 percent water saturation, you get a certain water-oil ratio, and what the shape of that curve is that you are using is a very important entity of any model. And I say a model -- it doesn't have to be anything as sophisticated as we have here with 4600 active nodes. Even the old model that we had, it was an important point. The end points of what will be the residual oil saturation, how much oil will be left behind after you sweep it 100 times with water, these numbers are important and these are the things that give reservoir engineers gray hair and turns thems prematurely bald or something, but it's nice to have a sounding board to discuss these things with, and so I have discussed these and I never did this alone. It's always

been in a group meeting. The State representatives would be there and, as a matter of fact, I've never talked to one operator alone yet to try to get some information, but you don't want to come out with something that's a mistake, and therefore we've had our meetings and they've been very fruitful. Also.....

BY: MR. MILES

I hate to interrupt you again and ask another basic.....

Is it 4600 active nodes -- are those grid blocks that.....

BY: DR. VAN POOLLEN

Yes, -- are nodes, grid blocks, cells. Again, they're all the same thing.

BY: MR. MILES

Joe and Hoyle were talking about 7600.

BY: DR. VAN POOLLEN

Those were totals.

BY: MR. MILES

Those are totals. What's the difference between the 7600 total and the 4600 active?

BY: DR. VAN POOLLEN

We might want to look at this grid here for a moment, but you put into the model a grid of I believe 22 by, what is it, 53 or so that we have, in six layers, but some of them will be on the other side of a barrier, and if they're on another side of the barrier, they're not connected to the reservoir, so that's -- as far as you are concerned, the

7600, I'd forget about it. I'd say 4600 active nodes. How many is that there, Joe? I've forgotten by now. I know it's.....

BY: MR. GREEN

That are active?

BY: DR. VAN POOLLEN

Well, total, that you have there on that.....

BY: MR. GREEN

About 7600.

BY: DR. VAN POOLLEN

Yeah, but I mean how many by how many?

BY: MR. GREEN

Oh. We're talking 24 by 45.

BY: DR. VAN POOLLEN

Twenty-four by 45 and then we have six layers in there, but we're not using all of these. We are assigning them as being no flow. There is no porosity in them on the outside of the field. Or in the aquifer, instead of using all of the cells, we have been assigning only a lesser number to represent the aquifer. Instead of just going all the way to the group range, we have stopped short.

BY: MR. MILES

Thank you, sir.

BY: DR. VAN POOLLEN

Well, we hear a word floating around and that's when I jumped

up a little bit ago when Joe Green was answering a question on the pseudo-curves. Now, the pseudo-curves. Now, the pseudo-curves are sadly enough kind of a mysterious kind of nomenclature for the layman. It's bad enough to talk about relative permeability curves, but if I just merely changed for you some terminology here, when we are talking about a relative permeability curve, that really says, what is the (indisc.) of all ratio at a given saturation. What is the free gas-oil ratio at a given saturation? Now, that is a rock property and a fluid property. When we start going to a reservoir model, we are representing a grid block, a cell, a node. We're giving it a certain characteristic, but if, for example, I inject water on this side of the table and the block is the size of all of these tables here in the middle, then the reservoir model would think that that drop of the water would immediately be disbursed throughout and it cannot in reality travel that fast. It will go real slowly, so we start kicking these curves. And there's a nice name for it. As they call it, pseudo in these curves, until you start matching, and that's what we first did in the fine grid, the thousand grid cross section until we obtained a match with observed field history. Then we extended these runs to generate a hypothetical history with a fine grid. And then we started to build a coarse grid block or a coarse grid cross section which only has 72 blocks, but each of these blocks will have

the same size as the ultimate 3-D. And so don't -- let me kick them a little bit more. I mean, keep changing them until we get a match between the coarse grid and the fine grid. That's what's called pseudo. As far as I'm concerned, for your purposes, it's nothing more than a mathematical crutch that we have to use in trying to get a better definition on a curve. So, you shouldn't allow yourself to get disturbed by that. That's something for us scientists to get disturbed about and have our haggles over. Besides the relative permeability, the fact that you saw on one of the cross sections a myriad of shale breaks, we have to represent these shale breaks by just a very few. If I only have six layers, I can only have five shale breaks -- so many openings, so many connections between the blocks, only five. So, again, we have to give them some pseudo-characteristics. Now, this has been very, very time consuming on our part to get these anywhere near correct and defendable. Now, that's one thing that I like to point out is that it's one thing if I'm making this study for an oil company that's just using it for their internal use, but it's another thing generating a study like this for a group such as this where the whole world is going to watch you and where any number that comes out could have a backlash somewhere and you cannot backtrack. Consequently, we spend a terrific amount of time going over all the details making sure that we have covered all of our tracks all the

time.

BY: MR. MILES

Mr. Chatterton?

BY: MR. CHATTERTON

Doctor, before you leave pseudo-functions, which I don't understand, first of all, how doyou enter these. Is this a potential or a capacitance difference or a mathematical formulation or what do you tell the computer? How do you get it committed or.....

BY: DR. VAN POOLLEN

Well, it's basically a variable resistor in a resistance network and the resistance that you are using depends on what the saturation is there so it is through those curves. It's the relative permeability curves which are the saturation-dependent variables. That's where we enter these.

BY: MR. CHATTERTON

One more question, if I may, Mr. Chairman. Doctor, having used this artifice technique, whatever it is, to get a history match, with your actual field performance to that point in time, if you were to hold those functions constantly, do you feel comfortable in so doing as far as any future predictions?

BY: DR. VAN POOLLEN

No, I never will feel comfortable. It's a very excellent question that you have there. The problem is that in reservoir modeling, you are trying to match under the mechanism

that the field is operating. Now, you start predicting under a different mechanism. You have no history to back it up against. And that, of course, is one of the reasons why it is worthwhile to take a certain part of the field and maybe get it over with and find out more about that part of the field or that's the advantage of saying water injection get started. Let's concentrate in one area and let's just learn some more about it so that we can then predict better into the future. If you don't have any matching without water flooding, you're just way out on a limb and you just have to use your -- I hate to use the word experience, but that's what it is. It's your experience and how you have done it in other reservoirs. Now, this reservoir modeling is not something that's brand new. It's something we have been doing. I have been involved in it since 1964. I wrote one of the first still-available commercial reservoir models, but that's still only 15 years. The industry itself is only about 15 years old so none of us really can go back and, what did you predict at this time and 25 years later, was it still good. In many instances, we cannot go back to the very beginning just to get test cases because the data did not exist. We have found through reservoir modeling that we need better and better data and we know what kind of data to get. That again is one of the advantages of doing a model like this. You might find that by predicting in this model

that you see the gas cap might come down in the next couple of years in a certain area, that's a good point to go for your observation wells to run some logs to see where the gas-oil contact is going, but to get back to your question to answer that, is you're still out somewhere on a limb, you know, and the more history you have the easier it is. Of course, if it field's depleted then I can tell you exactly what it was.

BY: MR. CHATTERTON

Thank you, doctor. Thank you, Mr. Chairman.

BY: MR. GREEN

Supplementally, though, I might add that in 24 years of engineering, we get more information, reservoir-wise at Prudhoe than I've had in all 23 years prior to that. It's beautiful.

BY: DR. VAN POOLLEN

Well, where are we now? We have finished our fine grid cross sections. We've checked them against the coarse grid cross sections. We feel relatively good about our pseudo-functions. The reason I am chuckling is that we're at pseudo-functions again. We presently have two prediction..... No, not prediction -- matching runs out on a 3-D model.

BY: MR. MILES

Two matching runs?

BY: DR. VAN POOLLEN

The matching runs means that I match the existing history. That means production up to date and that I can match the observed water-oil ratio, the observed gas-oil ratio and the observed pressures in the field since the start of the field until today. That part we call matching. To have that entirely finished probably takes me another -- and I hate to say a couple of weeks. I'm getting surprises all the time. It is a big tough job, but that's about where we are, and then thereafter we can start running our prediction runs and I'll volunteer that we'll be through some time in September and I hope that I will be proven correct on that. If I'm later, it doesn't mean that the model was wrong. It's just that I'm too slow, I guess, but it's just horrendous.

BY: MR. MILES

When you build -- the way I understand it, then, and I hate to keep asking -- interrupting you asking these basic questions, Doctor, but that's what you're here for, to help us out. Will you build, say, another eight or ten or twelve of these matching runs and then make your predictions from those? Is that -- is that.....

BY: DR. VAN POOLLEN

That's correct.

BY: MR. MILES

Approximately how many runs will you make?

BY: DR. VAN POOLLEN

Prediction runs?

BY: MR. MILES

Yes, sir.

BY: DR. VAN POOLLEN

We haven't fully finalized that, but we're talking in the order of ten to twelve runs that we ought to make, ten or twelve cases, and you've got to be relatively selective because they are so costly.

BY: MR. GREEN

In addition to these three-dimensional runs, we'll continue to make cross section runs, too, so we can determine some sensitivities with cross section runs which are a lot less expensive.

BY: MR. MILES

Thank you. Please continue, sir. Mr. Chatterton?

BY: MR. CHATTERTON

Yeah, I guess I've got a philosophical question of anybody that might want to answer it. Technically, I presume, and if this in substance is wrong, let me know, that with this 3-D model that the State is about to have or now has, and with our present Commission to enforce Title 31, why we're going to be able to make decisions as to the appropriate reservoir management to maximize ultimate recovery. Let's say that, given that, so to speak, -- I guess my question is, is there anything else we should be doing and then

particularly the question is, are we being penny wise and pound foolish? Sure, $5,000 to $15,000 a run sounds like a lot of money, and it is, but there's also a lot at stake, actually. I guess my question is, are we being penny wise and pound foolish? Would more runs do us any more good?

BY: MR. HAMILTON

Well, I think the answer to that, Chat, we'll have to look at the ten or so that we probably would run initially and we may find we'll need more runs. If so, we'll run them.

BY: MR. CHATTERTON

You're not being ultra-fiscally conservative, then, huh?

BY: MR. HAMILTON

No, but we do try to analyze each run very thoroughly before we make another one so that we're not running runs that we find later on, we have busts in them and they are meaningless.

BY: MR. CHATTERTON

I appreciate that. Thank you. Thank you, Mr. Chairman.

BY: DR. VAN POOLEN

You know, it seems kind of facetious to show you things, but this is just the information you get just for one matching run. It's the initial data that goes into it and you're talking about a stack of papers -- here, I'll waive it for the camera. I mean, it is just a horrendous number and to digest these, and it's just something out of this world, you know, and from some points of view to our advantage in

not going to full 3-D but taking this segment of the field, but my assignment is to do a full 3-D on the field and I dare-say that on certain sensitivities, we would be better off to just take a section of the field so a human being can digest this information.

BY: MR. MILES

Mr. McKinnon?

BY: MR. McKINNON

I just wanted to follow up on Chat's question concerning the number of runs you're doing. What are the variables going to be that you're going to be looking at?

BY: DR. VAN POOLLEN

Well, the variables will be different times of water injection. You don't have to go back to hindsight and say, what would have happened had you done it on day one, you know, from a practical day that water injection can start. So, different cases of that will be evaluated and different cases of gas sales will be evaluated, and we'll try to incorporate them with not penny economics but with reasonable economics. You cannot start gas cycling so much that you eventually burn more gas than you would be producing, so to speak, you know, so we try to keep some practical reason in it although we are not going to limit ourselves and say, we'll not do that because it costs money. But, basically, the runs will be similar in nature to the ones we did in our previous reports.

AGO 532215

BY: MR. McKINNON

Will you be looking at different rates of production?

BY: DR. VAN POOLLEN

Apparently so. I'm under instructions that I will do them under instructions of and in consultation with Joe Green and his group. I will not just myself just start running wild on this thing.

BY: MR. McKINNON

Are you currently planning on looking at anything below the current 1.2 million barrels a day?

BY: MR. HAMILTON

Yes, we'll make some runs.

BY: DR. VAN POOLLEN

I might say something about this rate sensitivity business. One of the cross sections that we have run at today's rate, we obtained a certain recovery. Then I halfed all the rates and ran it again and it didn't hardly make any difference at all.

BY: MR. McKINNON

What didn't make any difference, rate production?

BY: DR. VAN POOLLEN

The rates of production did not make any material on -- I've only got two-rate comparisons,-- right now in the fine grid cross section, and it didn't hardly make any difference -- when I say hardly, I don't even know which one was higher

and which one was lower. I mean, if I round them off to the nearest percent, they're the same.

BY: MR. McKINNON

What were the two rates you were looking at?

BY: DR. VAN POOLLEN

The ratios?

BY: MR. McKINNON

The two rates.

BY: DR. VAN POOLLEN

The rate is what today's rate was and that cross section, the way the wells were producing at this moment, actual production rates, and I took it in half.

BY: MR. McKINNON

And what were the other elements in the scenario -- in terms of gas sales or.....

BY: DR. VAN POOLLEN

No. They didn't sell any gas. I'm just talking about what has happened today and then predict that out to about -- well, to the end of this particular run, I mean, the end is when the wells quit producing.

BY: MR. GREEN

That was seven wells, I believe, and the maximum rate was around 68,000 barrels a day so the maximum rate under his second case would be 34,000 barrels a day, everything else being the same--reinject 90% of the gas.

BY: MR. McKINNON

Generally, though, how sensitive is a field to production--same rates of production the only variable. How sensitive is ultimate recovery to a.....

BY: DR. VAN POOLLEN

If you are looking at a 25-year line or you're looking at a 15 to 25 year line for sensitivity, in general, would be very small. You wouldn't see that much difference. Now, you take a field that you normally, in the normal set of circumstances, could issue 25 years, and you try to rip it out of there in 10 years, yeah, you're going to see some damage, but not the orders of magnitude that we're talking about here. This field is not even developed yet, you know, and we haven't even drilled, I'd say, well, in the order of half the wells have been drilled. The exact number that will be drilled depends on the final budget that people have, you know, but, I mean, we're still in a very active drilling situation and.....

BY: MR. McKINNON

I suppose that's kind of relative -- a very small percentage of effect on ultimate recovery here in a field this size could be a substantial amount of oil.

BY: DR. VAN POOLLEN

Well, I'd say maybe the answer ought to be that if I tell you that I think a certain field can produce 20,000,000 barrels,

that's a good guess I have, but I think that it's going to be 22 and I compare two thoughts. I mean, then I am not comparing to very precise things. If there's only -- if I'm going from 20 or 22 percent, I'll keep my eyes open for the run with 22 as time goes on, but I'm certainly not going to initiate that today if that has dangers involved, and you certainly aren't going to learn anything from this field if you're not going to produce any of it. You've got to produce at a certain rate and you've got to get some reservoir response. Here we've been at it for in the order of, let's say, 10 percent of the recoverable oil in that order, is what we're talking. You know, we only have 171 pound pressure drop. Luckily, we know all of this because we have so many measurements, but.....

UNIDENTIFIED SPEAKER

(Inaudible)

No, recoverable. I'm talking about recoverable oil. I'm not talking about the in place. The in place, of course, is a lot less than that--in place recovery. I would -- if the decision is, although I don't recommend it, to start making runs at half a million barrels, we'll make these runs, but I don't think, and it's my opinion, and I think my opinion ought to be something--I don't think it will make a whole heck of a lot of difference. Now, if you're asking me what would happened if it doubled the rate, I think then

you might start getting to do something that could become dangerous. I don't think we're shooting for 3,000,000 barrels per day at this moment at all. We have felt, and the work we have done, and it's not just our group, but it's the operators and I understand other studies have been made. I don't like to read them all because I get biased by it, but in general the numbers indicate that the one and one-half goal is a reasonable goal by all prudent measures, that various oil and gas commissions, that various operators, that different governments and different nations are using. Now, I would say that if we're going to a nation where things are highly hostile, you can get kicked out any minute, and people are just ripping it out of there at three to four times the what we think is the maximum efficient rate. Then we have some ground to stand on. I don't think that's what we're doing. That's my opinion. Of course, I'll be happy to make more runs, but we should not necessarily make them unwisely.

BY: MR. MILES

Mr. Parr?

BY: MR. PARR

We've all heard these reports that about 1985 to '87, Prudhoe Bay is going to start a very sharp decline. Now, as a result of this study, will we be able to verify the accuracy of that?

BY: DR. VAN POOLLEN

AGO 532220

Yes, we certainly should be able to do that and, of course, that decline will be related at the same time to what will be done at such a time about additional wells and/or additional pressure maintenance. I mean, if we're not going to have any water flooding at all at that time and the pressure is way down, then you will get that, and I'm just using that as an example. But, yes, we should be able to make that kind of forecast.

BY: MR. PARR

Another question. Suppose that we decide--we meaning the Legislature--decides as a matter of public policy that we want maximum BTU return out of that reservoir. I don't care whether the BTU is a gas or oil, but maximum BTU return, both in our own economic interests as a producer and in national interest as a source of energy. Will reasonably well informed laymen, like the Resources Committee here, be able to take that study--and also, of course, the Conservation Commission, too, on this--will be able to take that study and decide what the production rate should be and -- in other words, the policy makers will be able to use this study to make that kind of determination?

BY: DR. VAN POOLLEN

Yes.

BY: MR. PARR

It won't need translation? I'm not being facetious, really.

It's in the sense that it would be something that reasonably well-informed laymen who have attempted to understand the problem would be able to follow and use.

BY: DR. VAN POOLLEN

The answer is yes and, of course, in our reports, we try to indicate to you in -- well, don't say for laymen -- for management. We try to tell someone who needs to read that without having to go into all the mathematics themselves again and become a reservoir engineer over and over. We try to state these conclusions and I would say, yes, we can certainly do that.

BY: MR. PARR

I have one final question, Mr. Chairman. Is there a commonly accepted ratio of oil to gas production which gives maximum production or does such a thing not exist?

BY: DR. VAN POOLLEN

No, there's not a unique value.

BY: MR. PARR

It depends on the characteristics of the individual reservoir?

BY: DR. VAN POOLLEN

It depends on the characteristics of the reservoir. It depends on the relative volumes that are there--how much gas cap and how much oil ring is there, so if there were a unique value, then we may not need to make any of these studies. I mean, that's why we have so much of a hard time

making these studies--to find what the optimum -- and what is optimum, precisely. You never get precisely the optimum, but that's why we have to evaluate a field and say, well, it appears that -- and the GOR should not be more than so much. A field rule of GOR is even difficult. I mean, you might have to make exceptions for certain wells in a certain part of the field. Some wells should be allowed to be produced at a higher GOR than others, and eventually you'll get the overall maximum BTU value or the maximum oil or the maximum gas, whichever you are looking for.

BY: MR. PARR

Thank you.

BY: MR. MILES

Mr. Malone?

BY: MR. MALONE

Thank you, Mr. Chairman. Coming back to a question Mr. McKinnon, or maybe along the line Mr. McKinnon was pursuing then, basically, it looks as if there wouldn't be any significant difference in recovery of oil as produced at, say, half a million barrels a day or 1.2 million barrels a day over the life of the field, that the difference would not be substantial.

BY: DR. VAN POOLLEN

Cutting everything else back. By that, I mean if you are saying we will inject umpteen barrels of water in all cases

and always the same number, and you are not producing hardly any oil, you are going to drive the oil up into the gas cap, so if you are reducing the withdrawal rate, you've got to start reducing the injection rates by the same proportion, roughly speaking.

BY: MR. MALONE

So that the -- over that, say, order of magnitude, that the ultimate recovery that you'd expect would not probably change very much.

BY: DR. VAN POOLLEN

That's correct.

BY: MR. MALONE

In the preliminary analysis, I guess based on the two-dimensional model, what was the -- when was gas production or gas sales to start?

BY: DR. VAN POOLLEN

Five years -- at five years.

BY: MR. MALONE

That would be what--1982? Would the -- what would be the runs done on that to show what effect gas production in later years, like in 1983, or as more likely the case, 1985 or later, say, comparison made then as to how that might effect ultimate recovery of oil and gas from Prudhoe?

BY: DR. VAN POOLLEN

Todd, I'm looking at you. I believe that was part of your

study, was it not, to have the different timings on that, and maybe I should -- Dr. Doscher -- let him answer that. I did that on contract for him, but if you allow me, then -- is this the right report? They all look alike. Yeah, that's it. These are all the five years also. I thought we did them at different times.

BY: DR. DOSCHER

That was our best estimate at the time of when gas sales would take place, five years.

BY: MR. MILES

I'm looking at some that you have starting at different times--five, seven.

BY: DR. VAN POOLLEN

Yeah, there is a seven. Here, yeah, it's our own. It wasn't you, Todd, it was Hoyle and me. So, we have it starting at five, at seven and at nine years--that's the water injection. The gas sale has always been at five years.

BY: MR. CHATTERTON

May I correct you gentlemen, please, seeing as how I (inaudible simultaneous speech).

BY: MR. MILES

There's a gas sales at seven.

BY: MR. CHATTERTON

You ran them at 2.75 years after commencement of black oil production and at 6.75 years, and I call your attention to

your January, 1976 report.

BY: MR. MALONE

Mr. Chairman, the reason for the question is that it seems to be unlikely that there would be any large scale gas production until the pipeline's built and I doubt myself it will be completed until '85 at the earliest. But, we have some runs that were made there. The only other question I have on that was, at the time this evaluation was made, were the effect of the layers of shales taken into account on the mechanics production or was this something that was.....

BY: DR. DOSCHER

At the time that we were making the studies that have been published, we did not include any of the shales facts. At that time, we looked at the shales and were not able to correlate them well enough except in the lower-most part of the reservoir. We then made a shale study and were just about to delve into a major one here late last year. Then the operators had formed a group called the shale committee, I believe, or the shale study team, and they basically had just finished what we started to do, and we used their shale study indicating where shales were located but did our own correlation from well to well. We checked their shale study against certain wells where we had picked our shales and found sufficient correlation between their work and our work that we were willing to accept their work. It was a fantastic

piece of work, by the way, which maybe Smedley can tell me how many man-hours went into that, but it's highly documented and we liked it because of the numerical approach that the geologists had used to do this particular situation, so, to answer your question, in the earlier studies, we did not include any shales--in the present studies we are, but, at the same time, we're finding that the shales got to be somewhat leaky if you want to get any pressure matches and GOR, gas-oil ratio matches, at all.

BY: MR. MILES

Mr. Malone?

BY: MR. MALONE

Maybe the next question should go to the Commissioner, Mr. Hamilton. In evaluating a production plan by the field operators and proposal for change in production, whatever, what type of analysis would the Commission go through comparing, if any, the proposed operating plant, ultimate recovery and the amount of investment required. In other words, presumably, if I were in business, I would want to produce the field in such a way as to make the most money out of it, look on it as an investment, and I'd want to produce it in such a way as to make the most money out of it. Now, how does that figure in the Commission's evaluation of the proposed operating plan?

BY: MR. HAMILTON

We don't look at it the same way as an oil company would.

We basically look at maximizing the reserves. Now, in doing so, we can't completely divorce ourselves away from economics. In order to determine a reserve number, economics plays a part. You can't divorce yourself from it. Your cutoff, in estimating your reserves, your economic limit life is your cutoff. When the field reaches that economic limit rate, that determines when the field is shut in, so you have to take that into consideration. You also have to take in consideration that the operator has to produce the field at a sufficient rate to make some money. If you don't allow him to produce the field at a rate high enough to make some money, then the field will never be produced, so you won't have any reserves. So, in that light, we do have to consider economics, but as far as the investment is concerned, no, we do not take that into consideration.

BY: MR. MILES

Mr. Malone?

BY: MR. MALONE

The -- maybe there isn't time, Mr. Chairman, to pursue that particular question further, but I wanted to get some idea of how the economics are taken into account, and I realize we are running late for the session, I think.

BY: MR. MILES

Just for everybody's information, I sent a message to the Speaker that we were in a meeting here and if anything important

came up, to give us a call.

BY: MR. MALONE

May I continue?

BY: MR. MILES

Mr. Malone?

BY: MR. MALONE

Thank you. How do you take economics into account?

BY: MR. HAMILTON

We look at what we think might be an economic limit termination rate for the field. Right now, it's kind of a wild guess. We use, I think, 100,000 barrels a day as our cutoff rate before for the field. The Revenue Department, they even look into this as far as calculating their production tax. They use economic limit rates there, but we just have to make some kind of a rough guess based on what we think the operating costs might be at that time and the life of the field and then cut that run off at that time. As far as -- the other end of the scope -- as far as the rate that the operator wants to produce at, we look and see if the reservoir is sensitive to that rate. If it isn't sensitive to it, we allow the operator to produce at that rate and we don't bring economics in any other way. Now, the operator can come to us if we set a rate that he feels he can't produce the field at economically. He has a chance to come forth at the hearing and if we still don't change our conservation order, he can take us to court.

That's his course of action he can take.

BY: MR. MALONE

Then, presumably, if that happened, then, what would the producer -- present information that would argue that the economics aren't there under the Commission's order and would propose something else. Now, I guess the question I'm coming back to is, even when the resources run out, there's a ratio of some effect I would expect for the amount of investment if it's properly used and the number of wells that we drilled, how they produced and so forth -- rates, and the amount of oil that you ultimately recover. There's a ratio there depending on the quality of management, quality of technology. At this stage of the game, how deeply, I guess, has the Commission delved into that in trying to figure out, you know, production -- a viable production rate.

BY: MR. HAMILTON

We want a rate that doesn't damage that reservoir. That's what we're looking for and if what the operator wants to produce, from our studies, if we determine it will not damage the reservoir, then he's free to produce at whatever rate that is. For instance, the Cook Inlet fields down here. They're not rate sensitive. The operator can produce those at just as much oil as he can get out of those wells, but Prudhoe Bay, it is rate sensitive due to the gas cap. It's

AGO 532230

rate sensitive particularly to the withdrawal of gas, but again, we look at the reserves of the field under various operating modes and make our determination and if a particular rate is the maximum rate it should be produced at.

BY: MR. LOWENFEL

The limitation from a legal standpoint is not the economic liability of the operators. It's the conservation of the field, and I've advised the Commission, and I think the Commission has agreed, that if we get into that kind of a situation where the operator says, we cannot afford to do this, that that is an issue which a court should decide and not the Oil and Gas Conservation Commission. They are concerned with the conservation of the resource and destruction of the reservoir, not the economic liability of the operators producing the reservoir.

BY: MR. MALONE

Well, of course, what I'm trying to say is that if, for instance -- I think it was Brian brought up the question, maybe a hypothetical set of circumstances, more wells produced at lower rate might solve a specific problem. It also costs more money to build more wells and then the return for unit investment there, it seems to me, would probably go down because the oil is being produced at a longer period of time. What I'm wondering about is how those questions are resolved by the Commission in determining rates of production.

BY: MR. HAMILTON

Well, we can look at spacing, if that's what you're driving at, but we can't.....

BY: MR. MALONE

Well, not the spacing, but the -- what I'm really talking about is the.....

BY: MR. HAMILTON

Per well rate?

BY: MR. MALONE

The amount of money that's invested versus the ultimate recovery. Presumably, if you wanted to spend enough money, you could probably get 90 percent of the oil out but it would be long past any economic return.

BY: MR. HAMILTON

Yes, you could mine the oil and get it all out, but we have to live within the constraints of known technology, and we can't tell -- force the operator to do something that's completel ridiculous. We just have to live within what they can do under the present scheme of technology.

BY: MR. MALONE

As far as the technology goes, what I was asking is how the Commission evaluates, I guess, the economic life of the field under -- to make that determination.

BY: MR. HAMILTON

I don't know what else I can tell you other than how we calculate

reserves, and the reserves are the method of determining the conservation -- writing a conservation order, whatever will maximize those reserves.

BY: MR. MALONE

Maximize the total recovery from the field?

BY: MR. HAMILTON

Yes.

BY: MR. GREEN

Could I volunteer maybe a hypothetical that the operators want to produce 1.5 million a day and just, hypothetically, if the study indicated that they could produce over 2,000 barrels a day per well, then if they want to produce that many barrels a day, they'd have to drill this many wells. Is that what you're getting at?

BY: MR. MALONE

Um-hum.

BY: MR. GREEN

Yes, that could be an order that came in.

BY: MR. LOWENFEL

And if they felt that they couldn't meet that from an economic standpoint, the proper place -- of course, they would develop a record in front of the Commission, but the proper place to challenge the Commission's order, which is based only on the conservation of resources, would be in a court, in much the same way as the utility would go to the public

AGO 532233

utilities commission. The public utilities commission will either grant or deny a rate increase. They then, based upon the record developed in front of that Commission, go to court and say, that rate is confiscatory. The court is the one that determines whether or not it is confiscatory. In much the same way, I don't believe the Commission has the authority to determine, other than being somewhat prudent, that this rate is going to be confiscatory and therefore we're not going to order them to do this. If it makes good sense for the reservoir, then they're going to order it and if the operator's have a problem with that, it's up to the court to determine that, in fact, this is -- not illegal. That's not the proper term, but that it's not viable and it can't be done and there's no -- should be no force and effect given to the Commission order.

BY: MR. MILES

Mr. Malone?

BY: MR. MALONE

If the producer believes that the order, that the plan of production that the Commission approves and orders doesn't meet what they think is a fair return or an economic way to produce the field, then they can go to court on it.

BY: MR. HAMILTON

They'd first ask for a hearing and try to convince us that their figures are better than ours and actually they could

not -- there would be an economic loss to them to do something that we'd just written in our conservation order, were proposing to write, and then if we still wouldn't back off of it and we wrote that order, they'd have to take us to court. That would be the procedure.

BY: MR. MALONE

Have you encountered any such circumstances?

BY: MR. HAMILTON

Yes, in about 1972, we issued a no-flaring rule in the Cook Inlet and all the operators conformed to that ruling except Mobile Oil. They took us to court and they won their case in court. They didn't have to install the equipment on the platform that we insisted they would under our conservation order.

BY: MR. MALONE

In a case like that, then -- if the Commission doesn't cite a question like that, then maybe it's not the right place to ask the question but how would somebody determine whether a particular cost that the producer might incur in digging a requirement for proof reduction be confiscatory or not. Their expected rates of return on investment, are they taken as given or.....

BY: MR. HAMILTON

I think what the court might look at, at least in my view, for instance, if we insisted on a certain plan of action that

would call for the producer to invest X number of dollars and the producer could show that he wasn't going to get enough oil to even pay for that money, not on a present-worth basis or any discount basis, just flat the total value of the oil was less than his today's investment, I think you'd have a good case in court against us that we could not force him to do something of that nature.

BY: MR. MALONE

Is that the situation with the gas flare?

BY: MR. HAMILTON

Well, we thought it was something like that, but the court thought a little differently in Mobile's case.

BY: MR. MALONE

Thank you, Mr. Chairman.

BY: MR. MILES

I'd like to go back to something that Representative Malone was discussing earlier before we changed horses on the question of shale. You indicated that in the first runs, the extensive existence of shales in the reservoir were not plugged into these first runs.

BY: DR. VAN POOLLEN

Correct.

BY: MR. MILES

And now they're using them. What -- now you're using them because you know they're there. What does this generally

mean in a field--discovering shales to whatever extent substantial more than when you went in. What should that be telling the State? What should that be telling us that we should be doing? Does that change recovery? Does it mean we should delay water flooding, speed up water flooding?

BY: MR. HAMILTON

Mr. Chairman, we knew the shales were there back in '69 and '72 as well as we know they're there now.

BY: MR. MILES

Well, why weren't they plugged into the first runs, then?

BY: MR. HAMILTON

One of the reasons they weren't plugged in, we didn't have any history to match at all. It was a theoretical run. We didn't think adding the shales in there -- we might just add more problems than we could even handle on a theoretical run, and what we're finding now, putting the shales in, with the history, we're having to adjust those shales. We -- our geologic modeling -- we can't model them correctly without having some production history because we see this window effect that Dr. van Poollen was talking about, so I think, initially, if we had put them in, it might have caused us more problems than it would have helped. But we knew they were there. I mean.....

BY: MR. MILES

Okay, the fact is they weren't in the first runs. They're now being used..... What does that tell us?

AGO 532237

BY: DR. VAN POOLLEN

That we are having a better reservoir description, but we may well end up with the same answers.

BY: MR. GREEN

That's good news and bad news because it may be good news for secondary recovery. It may be bad news for gravity drainage.

BY: MR. MILES

What does it generally indicate in other fields?

BY: MR. GREEN

Just that. That in certain parts of the reservoir, it's not going to be a problem and in other parts it's going to be a benefit. Under one drive mechanism, it might be negative, but it might be positive in another one.

BY: DR. VAN POOLLEN

And we're having both mechanism going at the same time.

BY: MR. GREEN

Remember my analogy where I was saying that it confines water injection, that would be a benefit to have them. It would be a detriment if you were relying strictly on gravity drainage.

BY: DR. VAN POOLLEN

Mr. Chairman, may I just answer a question that I was not able to answer a little earlier relative to the delay of gas sales. We did run them and it's been a long time and

that's why I kind of forgot and also the results are not very dramatic. We have gas sales to start at 2.75 years and we have gas sales to start at 6.75 years and the results are identical--7.8 versus 7.8 billion barrels recovery and another comparison, 7.8 versus 7.8.

BY: MR. MILES

Are these in the '66 runs? I guess I just have a copy of your '77 supplement.

BY: DR. VAN POOLLEN

'76 -- January of '76 report.

BY: MR. MILES

Mr. Chatterton?

BY: MR. CHATTERTON

Yeah, Mr. Chairman, following up on Hugh's and your questioning about the fact that we did not put shale breaks in the 2-D models, I guess you will almost have automatically answered this question. Neither did we put in there or foresee, at least we didn't put into the models, the fact that these straws in the ground only have a limited lithologic exposure?

BY: MR. GREEN

Used 85%, I think.

BY: DR. VAN POOLLEN

No, we had -- we never had 100% exposure to any of our wells. We took the wells -- we had a standoff from the water and we had a standoff from the gas, in all instances,

so we never had a full exposure anywhere.

BY: MR. CHATTERTON

All right, fine, but did we visualize that -- well, we had the standoff, as you say, from the gas and the water. Did we also take into account that maintaining that standoff we were withdrawing from different lithologic units within the 440 feet of oil column?

BY: DR. VAN POOLLEN

Yes, we were withdrawing from different units.

BY: MR. CHATTERTON

And in the model even?

BY: DR. VAN POOLLEN

Yes.

BY: MR. CHATTERTON

Good. And we had it in the 3-D model?

BY: DR. VAN POOLLEN

And we have it in the 3-D now.

BY: MR. CHATTERTON

Thank you, sir. Thank you, Mr. Chairman.

BY: MR. MILES

Mr. Hayes?

BY: MR. HAYES

Thank you, Mr. Chairman. Just a follow-up question on one of the two or three previous questions. Is a field that's under water drive more rate sensitive than one that's been

gravity drained -- that's under gravity drain?

BY: DR. VAN POOLLEN

A field that's under gravity drainage usually is -- or can be rate sensitive if the permeabilities are somewhat low because what we're looking for is for the bubbles of gas to slowly travel up and the droplets of oil slowly to travel down and there is no way you can really speed it up. Now, if you don't allow the gas and the oil to migrate, you will not get the full effect of your gravity drainage, and so therefore there is some rate sensitivity in many instances. However, we have not found that in the ranges of rates that we are running these models at this moment. Now, a water dry field can also be rate sensitive. It might be that if you produce a field with a moderate water drive, if you produce it real fast, you may be producing it without any water cuts where, on the other hand, if you produce it real slowly, the aquifer has a chance to come in and actually, you will start producing water, so, yes, both of them could be rate sensitive. In this instance, we are looking at the aquifer not being overly active, as a matter of fact, probably not so active, unless we get a real surprise and consequently, everybody is looking at least to enhance the water drive by water injection. And when I say everybody, maybe I'm speaking out of terms, but I think the people behind me, they have done quite a bit of work and the ones at the hearing on that subject not so

long ago that indicates they are focusing their attention to that particular problem. I've covered two of your questions so far, but the rest of them will probably go a little bit faster. You're asking what type of pressure maintenance is now being used. Well, at this moment, we are only using the natural energy and plans are, I understand, to at least start injecting produced water and that will be a beginning of water injection and consideration is given for source water injection. No other means of pressure maintenance are considered other than we might recognize the fact that at this moment we're recycling approximately 90 percent of all the produced gas back into the gas cap so we do have gas cap pressure maintenance at this moment. I do like to say something about this so that people don't get the wrong idea about gas sales. The interesting thing is that the numbers we're talking about in the order of a million and a half and the order of two billion cubic feet of gas in sales and the relative size of the gas cap and the oil ring happen to result in that you get about the same gas saturation in the reservoir under either case, the reason being, if you keep injecting gas into the gas cap, the high pressure gas will actually finger into the reservoir where if you start producing it, some of it will come out of solution. And that's why we don't run into any real bottle necks here. If this gas cap were about one-third the size

of what it is, then it would be a very prominent question -- can you have gas sales or not, but with the sizes we're dealing with, it seems to balance out, and it's a gratuitous sort of situation. Some of these questions have five questions in them, but we already talked about the shales so I would like to just merely reiterate we knew about these shales for sure and I think we have said enough about them here so far. Then there was a question.....

BY: MR. MILES

Doctor, just a moment. Mr. McKinnon?

BY: MR. McKINNON

I wanted to back up to pressure maintenance. How soon will you be able to determine whether or not water flooding is necessary for maximum recovery from the reservoir?

BY: DR. VAN POOLLEN

So far, we're basing everything on laboratory data and I think we will know a lot more after initial water has been injected. It's our feeling, for sure, that water injection is something that is an important consideration but I even feel that it might be possible that water injection -- there's a remote chance that someone might want to stop water injection after they once got going because it could be a detrimental effect and you don't know until you try a certain amount of it. That's what we call pilot water floods and so you've got to take a certain part of the field and try it on there, and

our present recommendation is that you certainly ought to try it.

BY: MR. MILES

Right away?

BY: DR. VAN POOLLEN

When I say right away, I didn't mean on day one. I don't think anybody has been remiss. I think..... I think, yes, a pilot ought to be started right away and a diligent effort should be made.

BY: MR. McKINNON

Does the Commission have authority to order a pilot program water flood?

BY: MR. HAMILTON

When we reviewed this plan before, we encouraged the operators to start putting water in the ground as soon as they had enough available water in the field there and that rate at that time was determining about 100,000 barrels a day and, looking at our prediction at that time before the field started, it looked like they'd reach that volume in two years and they'd start putting the produced water away. Well, it turns out the water has not moved in as fast as we anticipated. It's up around 20,000 barrels a day now and we anticipated in 81 -- that it should be somewhere around 100,000 barrels a day and it will be returned to the reservoir. Now, they are running injectivity tests now to try to find out where

they should put this water in the reservoir and that's quite important as Dr. van Poollen says, to find out the best place to water flood the reservoir.

BY: MR. McKINNON

So, the pilot program won't start until '81?

BY: MR. HAMILTON

'81, yes, would be the earliest.

BY: MR. MILES

Can we get back to that? I guess maybe I'm getting two different signals. Are you guys saying different things? You're shaking your head no and.....

BY: DR. VAN POOLLEN

No, the answer is no. We're not saying different things, to the best of my knowledge. I said that diligent effort should be made. You cannot just go out there with a dump truck and water and you pump it in right now. I mean, you have to have enough water to start with. You cannot just start a..... So, why not wait until you get in the order of 100,000 barrels of water per day so you can put in a decent water injection system.

BY: MR. MILES

A pilot -- pilot.

BY: DR. VAN POOLLEN

That's correct.

BY: MR. McKINNON

Why not pump it out of the ocean?

BY: DR. VAN POOLLEN

Just pumping it out of the ocean is not the solution because if you don't treat that water, you may have all sorts of problems. The water from the ocean has silt in it. It could even have bacteria in it. You cannot just inject it just randomly and the wise thing is to first take the formation water that at least has the same kind of goop in it that already was there to start with.

(PORTION MISSING DUE TO CHANGE OF TAPE)

BY: MR. HAMILTON

.... we'll have enough produced water to return to the reservoir. Now, as far as using the seawater, they have filed for permits to obtain water from the ocean to use in their full-scale water-injection program. And they've also filed for permits to obtain approval for all their gas turbines and so forth needed to power all this injection equipment. And this comes under the EPA air pollution requirements that they have to meet. And when they get those permits, it's my understanding they'll order the equipment for the large-scale water-injection.

BY: MR. McKINNON

Well, there's no question of whether or not water-injection is going to take place there.

BY: MR. HAMILTON

It doesn't seem to be any question. It seems that it's coming and it's just a matter of when will it start. And the same is true we think for the gas sales. We are looking for a gas sales line, but we don't know exactly when that might come about either.

BY: MR. McKINNON

Do the companies believe that water injection's going to increase their recoverability?

BY: MR. HAMILTON

The studies that -- in discussions with them I think they do. They'll talk about this themselves when they have their presentation, but I don't think they'd be considering ordering this equipment, if they get these permits, if they didn't feel it was beneficial.

BY: MR. MILES

Mr. Chatterton?

BY: MR. CHATTERTON

Thank you, Mr. Chairman. Hoyle, these permits you talk about, that takes rather a sizeable environmental impact statement?

BY: MR. HAMILTON

Chat, I'm not sure what all it's going to take. They're kind of plowing new ground is my understanding, getting the air quality permits. They've turned in a voluminous volume of data and they've spent -- had to spend more time than he

anticipated preparing this information necessary to get the permits. They have no assurance from the federal government, and these are all federal permits that I'm talking about. I don't think they're having any problem with state permits. They have no assurance when the permits will be issued and the same with the Corps of Engineers. They have to get a permit from the Corps of Engineers to take the water out of the ocean to use for their injection water and also for back-flushing their filters that they'll be using for their large scale water injection, and there's no assurance from the Corps when they'll get those permits. They're hoping they'll get them here by May or so of next year at least so that they can order this equipment is my understanding.

BY: MR. CHATTERTON

Thank you. Thank you, Mr. Chairman.

BY: MR. MILES

Mr. Hayes?

BY: MR. HAYES

Just a follow-up on the water injection. Is waiting until you've generated enough water through oil extraction the normal way that you test the feasibility of water injection? Is that the way it's normally done in the industry or are we doing it up there because of this question that was raised about contamination and other problems? Is that the reason we're not starting our pilot program until we've generated

like 100,000 barrels a day? Is that the reason or is that the normal industry procedure?

BY: MR. HAMILTON

No, sometimes they can obtain water from other sources. This case, I think one of the things, it kind of coincides when the equipment's going to arrive. They'll have their injectivity tests, the on-going injectivity tests, completed by then so they'll have some better idea of where they want to inject the water and it coincides with when that 100,000 barrels a day will be available to inject.

BY: MR. HAYES

And you're saying this is not the normal -- not necessarily a normal industry proceedure, just that it's the best -- most feasible for this situation.

BY: MR. HAMILTON

I'd say there is no norm along those lines. Sometimes the source water, if it's compatible, wherever you get the water, with the reservoir water, you have no problem, but you do have to make sure whatever water you to the reservoir is compatible with the reservoir and the produced water, in this case, will be compatible.

BY: MR. HAYES

Have we determined that there are problems with sea water, that it is incompatible, or is that just conjecture, that there may be problems?

BY: MR. HAMILTON

The operators have done their studies on that and I don't know if they're completed or not, but to be truthful, I do know that, talking with them, initially they didn't think it was going to be a problem, but they wanted to go through a complete array of studies before they said for sure.

BY: MR. KUGLER

We're getting sea water (indisc.)

BY: MR. HAMILTON

No.

BY: DR. VAN POOLLEN

My statement on that was that you don't just want to take sea water and immediately start putting it in. You have to do quite a bit of analysis before you can really go and have at it.

BY: MR. KUGLER

It would be interesting to note that in the injectivity tests that one of the operating companies up there actually made formation water. They took another water and added chemicals to it until it was the same chemical constituent as Sadlerochit water to use to inject.

BY: MR. LOWENFEL

I'm not sure Representative McKinnon's question was directly answered, does the Commission have the authority to order water injection, and the answer is, yes.

BY: MR. MILES

Please continue, Dr. van Poollen.

BY: DR. VAN POOLLEN

Just so I can answer the question -- I don't know whether it's redundant here, but you have a question four which indicates that textbooks indicates water flooding would begin at the bubble point if there is no natural water drive and no gas cap drive. And then it goes on, assuming the textbook theory generally holds, when should water flooding at Prudhoe Bay begin. The main question, I think, that needs to be answered is, should you or should you not inject at the bubble point and what is the bubble point for Prudhoe Bay? For all practical purposes, the bubble point means if you lower the pressure any at all, gas bubbles come out of solution, and for all practical purposes, the majority of the field is at the bubble point from the very beginning. So, if you want to follow a textbook that says that you should be injecting when you reach the bubble point -- but I don't know that that textbook is necessarily entirely correct on that either. It's frequently indicated that you want to inject below the bubble point so if you have a reservoir that is above the bubble point, you just wait a little bit until you get some free bubbles in the reservoir and, consequently, you might reduce the residual oil. This is something that is open to considerable debate and I would say that if the textbook

merely says so, then that's just a cook book, and that is not necessarily my kind of textbook. So, that's the way I like to answer that. The Chairman left, but can I go on with the next question, I presume? Then, have you also analyzed other secondary recovery methods besides water flooding and so on? I might say that my company has done a considerable amount of work over the last few years. We put out an enhanced oil recovery digest indicating what all techniques are available in the world such as steam, combustion, CO2, nitrogen, (indisc.) and all of these, and just recently we had the pleasure, both Todd Doscher and myself were at a convention or a seminar for Department of Energy on enhanced oil recovery, and the state of the art is such that we are on the fringe of maybe breaking through somewhere, but we're not anywhere that we can say, hey, we have found the answer. First of all, there is not a ready answer. However, both of us feel, and I hope you don't mind me speaking for you, Todd, and disagree if you.....

BY: MR. DOSCHER

Go right ahead.

BY: DR. VAN POOLLEN

But we were together there. We both were hammering on the same thing. We've got to start an enhanced oil recovery research project for Prudhoe Bay. We're talking about recovering in the order of 40 percent, even say 50 percent,

just whatever number you want to use. You're leaving over half of the oil in the ground and over half of the oil is a tremendous amount of oil, so we definitely need to get started on a research project to start enhanced oil recovery and we are presently trying to get a team together so that we can start doing some work for CO2, which seems to be one of the possibilities. Now, I'm aware that several of the operators have already evaluated this and -- in their own shop, and again they are ahead of us in this respect, but as long as I don't have any full publications from them on it, I think it's very worthwhile that we start such a project and we are presently discussing that and me being, specifically my own organization, with the Department of Energy to get research funds to try to get something going. There are several arguments to say there is not enough CO2 in Prudhoe Bay to do the job and so you can always make your CO2 and I guess you could burn everything and then you have enough CO2, but that's not the solution to the problem, I dare say, but the fact is there is certainly enough CO2 for a certain part of the field and I think we ought to address that.

BY: MR. ZHAROFF

Excuse me, Doctor. Mr. Chatterton?

BY: MR. CHATTERTON

That's okay. He can finish, but I wanted to catch your attention.

BY: MR. ZHAROFF

Okay.

BY: DR. VAN POOLLEN

And by the same token, we also realize that there is this heavy oil tar, the (indisc.) underneath that reservoir which has, quote, unquote, unrecoverable oil. I have my personal feelings on it that it appears to me that -- and I may be speaking out of terms, but then again my observations are that that oil, even if it were not heavy oil, it would be very difficult to recover it anyway because it's nearly at the residual oil saturation already. But a research project should be aimed at this field and not just at the heavy oil zone, but on any additional recovery that might be gotten. However, don't have your hopes up too high.

BY: MR. ZHAROFF

Mr. Chatterton?

BY: MR. CHATTERTON

Thank you, Mr. Chairman. I may not like the answer I'm going to get but I'm going to get--but I'm going to spring the question anyway. Seeing as how I'm not hearing any comment from behind me, I guess that Doctor Todd agrees with you that it's appropriate for a research into enhanced recovery for Prudhoe Bay and you mentioned a few things. Would you care to comment on the prudency of keeping all options open on the possibility that enhanced recovery

AGO 532254

might be -- that you do come up with and find -- might be compatible with and only with gas injection?

BY: DR. VAN POOLLEN

I'm not sure I follow your question. I presume it's directed at me and not Todd.

BY: MR. CHATTERTON

It is and let me elucidate on it. I'm saying, basically, why, when you go into research, you don't know what your answer is going to be.

BY: DR. VAN POOLLEN

Correct.

BY: MR. CHATTERTON

(Indisc.) Okay. We had a horrendous gas cap there. That's obvious. We had a lot of solution gas. That's obvious. Okay, now, maybe in your research, you find an enhanced recovery mechanism. You mentioned CO2 for example and the swelling that it will cause. Doesn't it seem appropriate -- and my question is, speak to the prudency of keeping all options open for a potential such as that by keeping your gas cap present.

BY: DR. VAN POOLLEN

Now, I see what you're driving at. What you're saying is, it would be prudent not to produce any gas because you might need it.

BY: MR. CHATTERTON

AGO 532255

Roger.

BY: DR. VAN POOLLEN

And, in that case, it might even be better not to produce the field at all until we've learned all the research (indisc.)

BY: MR. CHATTERTON

I knew I wouldn't like the answer.

BY: DR. VAN POOLLEN

I would say that out of this meeting that we had in Williamsburg with the Department of Energy, probably the most important thing that came out, to me, is reservoir description. We've got to get better reservoir description, and I dare say that the little bit of enhanced oil recovery that we see today is because it's our research project and people are paying attention to their geology and they're getting a little bit more oil out of it, and it's not because of the chemicals that they're injecting, necessarily, but I think they have a much better reservoir description. To get reservoir description in this field, you need to core every hole in the ground and run every possible log on it. That's one possibility. Another possibility is to produce it and to get some history and find out where the shales are, where the geology is really located and consequently drill your wells more effectively and drain them better and I think that is where the answer is going to be. I'm afraid

that if we're going to wait for enhanced oil recovery, it's just going to be too late. I know that the company I used to work for, they have been at it now for about 20 years. They're now producing nationwide 3,000 barrels of oil out of that research project and I don't think that that's a very wise thing for us to keep waiting for.

BY: MR. CHATTERTON

Thank you. Thank you, Mr. Chairman.

BY: DR. VAN POOLLEN

I believe that -- oh, wait a minute. One other section. Yeah, there's two more questions that -- already -- one of them has been touched on, and that is the accuracy of a simulated computer model. Again, if you have no history on the mechanism that you're studying, that means if you haven't produced the field at all yet, or if you don't have any water/oil ratio history, you're just trying to put in the best possible parameters and you can merely say, well, this is better than that, and I think, again, it's rather pleasing that we're coming so close after a year and a half of production to what we predicted with a rather simple model, and I think the more description we put into this, the closer we will come. As far as -- and I believe somewhere in here, it says, can we go with these numbers to the bank? Yeah, you can go with them to the bank, but I think the bank will discount them also under any and all circumstances.

Now, the next question is do we have the capability of monitoring Prudhoe Bay reservoir performance to the extent necessary to protect the State's interest. I would say yes. The answer is that we have the capability. We can run all sorts of logs to monitor the advance of the gas/oil contact, and it's being done. I don't need to tell you what kind of logs they are, but certainly the utmost is being tried there to monitor the advance of the gas cap. The same way, to what extent is the water that is coming in. Are we tracking this? Yes, there are logs available. It's being done. I think we're getting a fantastically large number of pressures. Pressure interference tests have been performed and basically are still being performed. And then I think the fact that these models are constructive and they're being run in an effort to keep matching, I dare say that all technically feasible monitoring techniques that exist are being done. And I would also like to say that there are very few governmental organizations that monitor a field that's under their jurisdiction as they do here in Alaska. And this is no flattery. Another one might be ....

BY: MR. MILES

A lot of other people thought so (indisc. - simultaneous conversation).

BY: DR. VAN POOLLEN

Well, there are a lot of other people doing it, also. That's

correct. But ALBERTA (ph) is scientifically oriented. The Oil and Gas Conservation -- whatever they call themselves there. They have their own reservoir models. There are very few other governmental agencies that actually go to the extent that we're going here. And I think the monitoring is done fairly well, both by the operators and the government. Unless you have any further questions, that would be basically what I would like to say.

BY: MR. MILES

Representative Hayes.

BY: MR. HAYES

A general question, Mr. Chairman. Are you going to be around tomorrow, Doctor?

BY: DR. VAN POOLLEN

I'll be here tomorrow. I don't know to what extent I'll be involved, but I'll be sitting there like they do now.

BY: MR. HAYES

Is it correct, Mr. Chairman, that tomorrow Dr. Doscher will be testifying? I -- there might be some questions generated by his testimony that we'd want to ask.

BY: MR. MILES

Yes, that's right.

BY: MR. HAYES

That's -- that's the only question I have.

BY: DR. VAN POOLLEN

May I ask Dr. Doscher if he has any comments on what I said just now; I mean, that you take exception to, or do you want to wait until tomorrow? We are working so closely together with the same time but not the same people at all. We're having a pretty different ....

BY: DR. DOSCHER

We'd just as well wait 'til tomorrow. There are just some fine points which I think I'd like to bring out. Basically I think you made a very good presentation.

BY: MR. MILES

Mr. Parr.

BY: MR. PARR

I'm not sure to whom to address this question. But, in talking about the water flooding the other day, a while ago when somebody mentioned 1981 as the time at which it would start, what percentage of the recoverable oil at Prudhoe will have been taken out at that time?

BY: MR. HAMILTON

Well, let's see. We've produced, I think roughly, about 2.6%, somewhere thereabouts, of the total.

(Various members of the audience offer percentages.)

BY: MR. HAMILTON

About 20% of the recoverable oil, sir.

BY: MR. CHATTERTON

I think Dr. Van Poollen said roughly 10% will have been taken out by the time this project in 1981 is (indisc. - simultan-

eous conversation).

(Conversation in background regarding percentages.)

BY: MR. HAMILTON

Okay.. 15 to 16. Our computer-minded man ....

BY: MR. MILES

Mr. Chatterton.

BY: MR. CHATTERTON

Yeah. One real general question. I gather that water flooding waspretty much in its infancy in the early 40's, and it has become a very well-accepted secondary recovery method. Since the early 40's, or whenever its conception was -- that order of magnitude -- how many fields do you believe was water flooding ever commenced as early in the productive life of that field as is being proposed here?

BY: DR. VAN POOLLEN

Very few.

BY: MR. CHATTERTON

Do you think there's any?

BY: MR. GREEN

One I can think of. An extension of Wilmington. But, in that situation, they knew exactly what they were getting into. It was merely an extension of an existing field. And the ironic thing about that, the area of the reservoir that was -- water flooding was instituted initially, and that was primarily to avoid subsidence. For those of you who are familiar with

oil recovery, Wilmington had a classic subsidence problem. The recovery in the area that has water flooding initiated initially with (indisc.) production, is going to be let 20% less than the area that underwent subsidence, and then later, some 15 to 20 years later, they injected water.

BY: DR. DOSCHER

One moment, one moment. Can I -- will you give me a chance to answer some of this accurately. Right now? I think this was an unfair comparison about the water flooding at Wilmington because where they initiated the water flood the field had been depleted a lot more than it had originally -- than they originally expected, so there had been a lot of drainage there. So it's not a very fair comparison. Now water flooding historically was not introduced to begin with at the early life of the field because most of our large fields in the United States were discovered in the 20's and 30's when there was no real desire for conservation but mostly for turning the maximum profitability possible. And, of course, it wasn't until the discoveries in east Texas that led to the Railroad Commission and then subsequently made the restrictions on production. And then water flooding still did not come into America until really after World War II. In recent times, for example in the North Sea, the Brent (ph) Field is water flooded from day one. It's an under-saturated field and has a bit of a gas cap, too, not too different from Prudhoe Bay;

HOUSE RESOURCES COMMITTEE MEETING

ON

PRUDHOE BAY RESERVOIR MANAGEMENT

ROOM 118 - CAPITOL BUILDING

JUNEAU, ALASKA

August 6 and 7, 1979

Volume II

Pages 151 - 300

J & R Associates

P.O. Box 29 • Douglas, Alaska 99824

Judy Jones
586-6846

Rita Stoinich
789-0208

AGO 532263

a much smaller gas cap. It still has gas caps. And there are many fields in Alberta which, although they were not flooded from day one, do get the instructions that water flooding will be very early. So, in general, in modern times if there is no natural water flood drive and the field is being managed well, plans for a water flood will come in very early, only pending the resolution of the drilling patterns and things of that sort. That's the best of my knowledge.

BY: MR. GREEN

I might take exception to that, Doctor. In Wilmington, the Fault Block 6 - Fault Block 5 area was the common line between the on-shore and off-shore. If you equate those two fault blocks recovery, the recovery is still 20% less in the off-shore, and this is confirmed by Harry Stodd (ph) the senior engineer. This would be at Longridge (ph).

BY: DR. DOSCHER

As I said, there was a lot of drainage. And, of course, it's very difficult when you have drainage to know where the -- the oil went to until (indisc.). But I don't think you could attribute that at all to water flooding.

BY: MR. GREEN

He does. (Laughter)

BY: DR. VAN POOLLEN

I know of a couple of fields that I've been involved in where we did start real early water flooding. They both happened

to be in Libya. One is a reef with a 4,000-foot oil column that we're injecting water from the very beginning from the bottom up, so immediately generating an aquifer. Another one out there was the Wah (ph) Field which Oasis Oil Company had. They found that they didn't have enough of an active water drive, and they were afraid to go below the bubble point because then the pumps wouldn't run anymore for their lift system. So there's one. And then in Abu Dhaby there is a big field where they started immediately with a what they call a dump flood. So there are some of the bigger fields where this is done. Mobil Oil Company was planning on immediately starting to inject water in one of their fields in Libya, so they ran two pipelines; one pipeline to carry the oil to the shore and another one to carry the seawater. It turned out the field was so good they used both the lines to carry oil, and they haven't gotten around to the water flooding part. (Laughter) But there's also a great danger. And, as long as the question was asked of me, what is the textbook time to start injecting water, another textbook statement is - don't inject water in a gravity-drainage field, because you will take that 65% number in that good part. If you inject water you will ruin it right down to 30%, or something like that, because of three-phase relative permeability that you might get. So we cannot generalize is what I'm trying to say.

BY: MR. KRUGER

We had one field in Alaska, too, that started water flood from day one, and that's the McArthur (ph) River Field.

BY: MR. MILES

If it happens that the pressure in the field drops substantially, or we find that perhaps water flooding has started too late, is that irreparable to overall maximum recovery?

BY: DR. VAN POOLLEN

Within reason, there is no great concern.

BY: MR. MILES

Thank you.

BY: DR. DOSCHER

Well, I guess we should wait 'til tomorrow. Okay?

BY: MR. MILES

Okay. Any other questions for Dr. Van Poollen? Dr. Van Poollen, thank you so much. Certainly we've all learned a lot.

BY: DR. VAN POOLLEN

Members of the Commission, thank you very much.

BY: MR. MILES

We'll stand recessed until tomorrow. Hopefully, the tentative time is 1:30, but lord only knows. (Laughter)

August 7, 1979

1:30 p.m.

BY: MR. MILES

Let's recall this committee back to order. Ah... prior to beginning I might advise the legislators present that we will be called should anything happen on the second floor. Well.. ah..there's only seven or eight of us here, they don't need us. It's you and 23 or 24 other people Chat, but..ah..the leadership will advise us -- keep us posted if anything urgent happens. Our first witness today is the Legislative Consultant on Prudhoe Bay, in general, I guess, Dr. Doscher.

BY: DR. DOSCHER

May I sit here?

BY: MR. MILES

Certainly can Doctor. Dr. Doscher..ah..about 20 minutes ago gave me a copy of..ah..the first report we requested in the amended contract, we are having copies made for committee members now and they'll be -- they'll be, should be finished in ten or fifteen minutes. So..ah..Dr. Doscher, it's all yours.

BY: DR. DOSCHER

I'd like to first check in with you and tell you why I was hired by the Legislative Affairs Agency of the State of Alaska, what my role, what I think my role was and still is,

AGO 532267

and before I do that and go on to the rest of the report, I do want to dispel any..ah..notions that..ah.. because I am a teacher, that my experience is confined to the classroom, and so for the record I'd like to note to those who are not aware of it that I am a licensed engineer in the states of California and Texas and the Province of Alberta, I have served as a consultant for the head office in petroleum engineering of a major intergrated oil company for whom I worked for 25 years. I'm a consultant to the..ah..agencies in the country of Venezuela, Canada and as the (indisc) Professor of Petroleum Engineering at the University of Southern California to the National Iranian Oil Company. My experience is fairly broad in the industry having started out..ah.. drilling wells in Signal Hill. I've patented some drilling muds and it ranges from there all the way up to leading a task force that achieved the first (Indisc.) to production from the Athabasca Tar Sands in Canada, and to many other things since then. Now, I was first hired by the state for the explicit purpose of reviewing the operating plans for Prudhoe Bay that were provided by the operators approximately two years ago. And, implicit in the charge we had, at that time I was working with my associate Professor Dougherty at the University explicit in the charge was, will gas sales affect the recovery from Prudhoe Bay, and the recovery there again

explicitly was recovery of crude oil. It was with this in mind that we reviewed the operators' plans. Now the information that we were supplied with from the operators, based on the overall nature of their operation, our superficial view of this was very simple, they were doing something wrong according to the text book. They were allowing the pressure to come down in the reservoir. Now, the reason we didn't turn right around and say this is wrong is because we know from our experience that oil fields are very, very unique individuals. The population of oil fields, although one thinks that there are a lot of oil fields in the world, the population is rather small and it's very difficult to get a statistical correlation between recovery efficiency in an oil field and the many parameters to which the oil flow and gas flow responds. So that even though superficially we say a sin was being committed by not keeping the pressure on the reservoir, this was not an adequate answer and we had to go a little more deeply into the questions of why pressure was not being maintained. Now, just to recall to you what a release in pressure does, a release in pressure, essentially, takes the energy away from the reservoir by which the reservoir is kept alive. If it doesn't have energy, it can't function and when you release the pressure you are taking energy away from it. In the early years of our industry, way back in Appalachian oil fields and some of those in south Texas, the

pressure was released very quickly in the oil fields and as a result the recovery there was extremely poor. However, it wasn't only a long time ago that this was done, it was still being done fairly recently, for example in Iran, where the great oil fields there operated by the consortium..ah..the gas was allowed to be flared and some of it sold to Russia, but nothing was done about maintaining pressure. And only in recent times has the National Oil Company tried to restore the pressure by reinjecting gas that was being produced from the fields and even going so far as to look for dry gas fields, non-associated gas, and return the gas to the reservoir, in an attempt to redo or take care of some of the damage that had been done by the previous release of energy. So, it was with this kind of background then that we started looking at, a little more closely at why the operators believed that they could, indeed, sell gas from the reservoir, allow the pressure to drift down and still get a high recovery. Now, it soon became apparent that we couldn't possibly by our study come to any definite conclusion. We could see some of the things that they pointed to which they thought would work for them. Mainly, there was the possibility of significant drainage of oil, gravity drainage. There was a significant possibility of the gas cap expanding and displacing the oil ahead of it and giving fairly low residuals. But, we had to admit that we really couldn't tell and the only way to tell was for the

State to operate its own 3-D Model. And so we strongly recommended to the State that they appropriate money for a 3-D Model to be done on their behalf. And they did approve this, and you've heard of the developments with the 3-D Model. Our basic conclusion then was until the study from the 3-D Model was done, one could not permit gas sales for fear that premature gas sales, loss of pressure, would result in an irrevokable loss of crude oil recovery from the reservoir. Now, despite the acceptance of this proposal, the Legislative Affairs Agency and this committee did still want some consistant runs with the VanPoolen Model which would -- have the 2-D Model which had been developed for the Conservation Commission. They wanted to know if you used that in a consistant manner, what would that tell you about gas sales and water flooding. And so, we accepted another contract from the State in order to ask Mr. VanPoollen, VanPoollen and Associates, to essentially operate their model to investigate what would happen according to the description of runs which we gave them, not changing the nature of the model, but just the nature of the runs. Now, we had those runs done and we delivered that about a year ago and bearing in mind that the VanPoollen Model of the time, State's model that VanPoollen developed, is only a two- dimensional model and has great limitations. This...these runs were done to get a sense of what was happening. And the sense was this, that if you sold

gas you would lose about 3/4 to a billion barrels of oil. And if your water flooded, you might get a little more than that back, and if your water flooded and didn't sell gas, you might get an additional billion barrels of oil. Now, as I say, these just gave us a sense of what was going on with a model which is not sophisticated and had some obvious defects in it. This about ended our direct involvement at the time, except the Legislature Affairs Agency came back and asked us if we would pursue an overview of the development of the new 3-D Model, the contract for which was eventually awarded to H. D. VanPoollen and Associates, and we agreed to do so. Ah.. you've heard some of the progress on the model or the progress as Hank VanPoollen has described it and now I would like to return to the -- what we were originally asked to do and that is an overview or a...critique of the operators original plan. Now the operators projected a performance history with their numerical simulator, such that 36% of the original oil in place would be recovered. This with gas sales, no pressure maintenance and no water flooding. The mechanism -- the general mechanism behind this was that the oil in the reservoir under the influence of an expanding gas cap would undergo significant gravity drainage as a result of the relatively unimpeded vertical permeability. We noted for the legislature that the conceptualized gravity drainage which seemed to dominate the system, could be

mitigated by gas coning and shale breaks within the reservoir. We felt that both factors might indeed be far more significant than that predicted by the particular reservoir description developed by the operators. Our experience did not indicate to us that the properties of the Prudhoe Bay reservoir would permit such a high recovery to be reached by the proposed operating plan. We noted to the legislature that information we had access to suggested that high recoveries of this kind, and this is indeed a high recovery without secondary operations, was usually confined to reservoirs which had significantly more favorable characteristics than those of Prudhoe Bay, particularly the permeability, the pore size distribution of the reservoir. We had also significant evidence that if unaided gravity drainage would be affected, unaided that is by no further gas injection, if that were true then recovery efficiency would still be higher if you maintained pressure while the gravity segregation took place. Now in information which Exxon presented to the United States Congress, they give a list of six reservoirs which apparently gave rather unequivocal support for our position. They cited this list of six reservoirs and said that in these gravity drainage reservoirs the recovery was between 47 and 87%, but what Exxon did not specifically reveal is that these six reservoirs were subjected to gas injection and in each one of these reservoirs

for which data has been obtained, the oil mobility is significantly greater than that in Prudhoe Bay. By....

BY: MR. MILES

If I could interrupt.

BY: DR. DOSCHER

Um hum, anytime.

BY: MR. MILES

Subjected to the gas injection, for what period of time, is there an average period of time?

BY: DR. DOSCHER

I'd have to look up the data but all of them were finished up by gas injection.

BY: MR. MILES

I see, and that...does that preclude gas...any gas sales at all to your knowledge.

BY: DR. DOSCHER

No, no, no this is...now, I'm talking about these six reservoirs out here.

BY: MR. MILES

Right.

BY: DR. DOSCHER

Okay, I don't even know where they got the gas, whether they got the gas from the same reservoir or from someplace else. But what I am speaking to here is that, in these six reservoirs for which the recovery efficiency was so high,

gas was reinjected to maximize the gravity drainage.

BY: MR. MILES

I see, and that was through the duration of the productive life of the field?

BY: DR. DOSCHER

I cannot tell you whether it was over the total life, it certainly was in the latter life and in some cases may have extended into the early life. For example, in the classical example here, the Mile 6 Peru field, Mile 6 field in Peru, ..ah..as I recall, and I'll have to check this, but I believe gas because it had no utility there was reinjected throughout the life, but that's subject to confirmation but I believe that's true.

BY: MR. MILES

Thank you sir.

BY: DR. DOSCHER

Now this data in the submission to Congress was projected by Exxon to Prudhoe Bay and they state the recovery efficiency would be a whopping 65%. Now, this value is 180% greater than the 36% predicted for gravity advantage which does not use reinjection. Now, in all honesty and fairness, I believe that Exxon projection of a pressure assisted recovery of 65% at Prudhoe Bay is optimistic since it doesn't adequately take into account the shales that are disseminated through the reservoir, but the important conclusion is this, and the one

we profess to in our report. Gravity drainage under pressure maintenance, gas injection or reinjection, is a damn good recovery mechanism in amenable reservoirs. Now, to further substantiate this position, I'll quote from a textbook. The textbook happens to be one written by Morris Muscat (ph) almost thirty years ago, it's a classical text that's never been duplicated, it's called Physical Principles of Oil Production, and he analyzed the behavior of many fields in that book, one of them being the Mile 6 Peru field listed by Exxon. He calls attention to the maintenance of pressure in supplementing the effect of gravity forces. He says this maintains a high oil saturation in the down structure region, it sustains flowing production, it increases sweep efficiency, and then concludes "the most efficient type of gravity drainage production will be that of the extreme idealized case where by pressure maintenance no gas is allowed to evolve in the oil zone.

BY: MR. MILES

What does that mean?

BY: DR. DOSCHER

That means that if the ideal case, if you want most of the oil out, keep the pressure in the gas cap exactly where it was and get your oil out by pushing it out, say with water from below. And if you have to take the gas out to put it all back in to maintain the gas oil content.

BY: MR. MILES

I see, put it all back in the gas cap.

BY: DR. DOSCHER

Put it all back in and if you have to use up some, find some to make it up. Now, Exxon and BP in information they submitted to the Congress, disputed our contention that obtaining a low residual oil saturation in the expanded gas cap is a requirement for good recovery. Exxon declares the decision on the timing for a gas sale is not dependent on the residual oil saturation in the gas invaded areas. But, then in the next sentence says, if it did turn out that the residual oil saturations actually observed were higher than predicted the operating plan could be, not would be, but could be, altered to include a larger volume of water injection at an earlier date than now invisioned being necessary to recover the oil. BP made a similar statement saying that lower ultimate oil recovery would also result with or without gas sales. However, it should be assumed, they say, that the operators will adjust the operating plan to assure efficient recovery. A number of modifications can be made, they say, a source waterflood to help retard the gas/oil contact advance could be added. Now, our point is this, unless the facilities for water injection are on standby, then neither operator would be able to respond to this situation with any speed. It requires three to five years to design and implement a

water source and several more still to catch up with the declining pressure. Further delays could result over considerations of crude prices, taxes and so forth and whether the anticipated return on the investment in the water flood is commensurate with the operator's expectations for competitive investment. We would note that, in connection with this, that although simulations of the operators included the injection of produced water from the time zero, no produced water has been routinely injected into this sadlerochit reservoir. Now, certainly the water production has been less than anticipated but there are no standby facilities to get it in the moment it reaches any needed value. So it's the basis of all this that we reached the conclusion, we reached the conclusion that gas sales should not be committed until the need for water injection, to at least compensate for gas withdrawals is firmly established and still not then. Not until, as the former Director of the Division of Oil and Gas Conservation has said, until "the operators adopt and implement a source water injection program in order to avoid jeopordizing ultimate oil recovery." Now, when you consider water flooding there is much more to it than just with reference to whether it can offset the negative effect of gas sales. A much more appropriate question to be posed is that if a water injection can and by how much increase recovery in the absence of gas sales. Our application of the

VanPoollen and Associates model indicate an increase of no less than 4% in the absolute recovery efficiency about a billion barrels above the highest values otherwise achievable by implementing water flooding and no gas sales. I anticipate the more sophisticated model now in development will probably show an even larger difference. The results of such studies are very badly needed if water is to be injected since pressure maintenance by water injection, pressure maintenance by water injection is far better than water flooding after the pressure has declined. Again....

BY: MR. MILES

I'm getting confused.

BY: DR. DOSCHER

Okay.

BY: MR. MILES

Ah.. the difference between water injection and water flooding. When you use the term water injection are you -- or water flooding are you presuming source water?

BY: DR. DOSCHER

Oh yes. In oil here, you need source water.

BY: MR. MILES

Okay, and are your presuming, are you presuming produced water when you say water injection?

BY: DR. DOSCHER

No, no. Water injection for pressure maintenance means putting

the water early before the pressure has substantially declined.

BY: MR. MILES

Okay, where does this water come from?

BY: DR. DOSCHER

Oh, it can come from any place.

BY: MR. MILES

Probably source water.

BY: DR. DOSCHER

Oh, it's a source water, yes, it comes from the rain, it can come from the sea, it can come from any place you can lay your hands on it. Okay? But water flooding, it's a fine point here, water flooding refers to, you've let the pressure decline then you put the water in to flood the oil out.

BY: MR. MILES:

So, water flooding is essentially a catch-up..ah..water injection, the way you explain it, is a preventative.

BY: DR. DOSCHER

Right. Exactly. One would call it, the first one pressure maintenance by water injection and the other is water flooding.

BY: MR. MILES:

I see. To bring the pressure up to....

BY: DR. DOSCHER

....and bring the pressure up.

BY: MR. MILES

Thank you.

BY: DR. DOSCHER

Okay. Again I quote Muscat (ph) "there is practically no major physical factor making secondary recovery," that is water flooding after pressure decline, "advantageous as compared with similar fluid injection before substantial pressure reduction has occurred." The only reason then for delaying injection of water in reservoirs without a natural water influx is economics. But the economics has -- be considered not in a vacuum. It must be estimated with respect to the several interests that will receive the benefits. The economic value to the State and nation of various schemes for operating the Prudhoe Bay field must be developed by the State on its own behalf, and this was basically the thrust of our recommendation. Now, let me say something about water flooding which is not in my report, but appropo of some of the comments that were made yesterday. Fields with natural water invasion, in general, show the highest recovery efficiency of any fields in the world.

BY: MR. MILES

Well, what's water invasion?

BY: DR. DOSCHER

Well natural...natural water flood. In other words, the oil reservoir is next to a water aquifer, okay? So

natural water drive.

BY: MR. MILES

Okay.

BY: DR. DOSCHER

The East Texas field is probably the greatest example of this. It has a natural slow water influx, production has been managed by the State because of competitive influences since the early 30's and the recovery efficiency there is going to be over 80%. Now, that's a very special field, don't...I'm not trying to tell you that all water floods are going to be 80%. But, natural water invasion in a good reservoir gives you these high recoveries. Cores taken from behind the water invaded region in East Texas give oil residuals as low as 4 and 5%. The oil is substantially swept out. All along the south...Louisianna and south Texas coast, where we have natural water invasion, we see the same thing. A slow natural water influx is apparently unbeatable. There are some places where you can by restoring gas in very good reservoirs as Exxon has pointed out, yet recoveries that are comfortable. Water flooding, in general, does not require too much piloting as suggested yesterday, in my thinking, because you can't tell very much from a water pilot unless you go in and do it on a fairly large scale or go in and drill an extensive number core holes. The original water pilots, many of which were pioneered by the company I formerly

worked with, were primarily to get some basic knowledge of sweep efficiency in the reservoir and was readily, rapidly concluded that it was not working because when you just water flood a spot in the reservoir, the water goes out all over and it's very difficult to confine. So, that water piloting, since we have learned this, is usually confined to basically determining injectivity and this is a very serious matter. Now, one of the things that also is involved when we talk about water injectivity, putting water into the reservoir, which was not brought out too strongly yesterday, but if you have shales and you say you're going to confine the water to within the shales, this is a tremendous mechanical problem because in the hole, in the subsurface, there will be many intervals between shales, there may be three, there may be five, there may be ten, and if you're going to water out between the shales you've got to make sure to get the water in between each and every set of shales, and this is a man-size problem, a very difficult problem. So, just

saying we've got shales and this is going to help water flooding is not an adequate answer. It may help you in keeping the water confined, but first of all you've got to get it in and I say that as offsetting the fact that I say water flooding is good, there are many problems and you can't really tell in advance how good or how bad you're going to turn out. The way you get water in you get the oil out.

I'd like to bring the State's attention to way the Province of Alberta manages its reserves. The Province produced in 1977 only a million barrels of crude oil and had a proven reserve of 5.4 billion at the end of that year. The Province is one of the most richest, one of the richest and most solvent political entities in the world. Its oil and gas conservation board maintains its own technical staff which analyzes all new pool discoveries. An operator can be excused from committing a pressure maintenance program only if it is concluded would not recover additional economic reserves. The Province's evaluation of recovery and economics is the initial framework for any discussion on the subject. The Province reports that 3.8 billion barrels of its total reserves have been added by pressure maintenance compared to 7.6 realized from natural depletion. The need for this State to have its own appraisal of Prudhoe Bay is obvious and it is very rewarding to see the State going ahead with it. Its unfortunate that the study being undertaken by VanPoollen and Associates is taking somewhat longer than I had originally estimated to this committee. One of the major problems in this study has been the assignment of permiabilities and the positioning of the shale barriers in the model of the reservoir. Both of these parameters are of critical importance in effecting the outcome of the simulation and it is for this reason that VanPoollen and Associates have

done it very methodically, very well to leave as little doubt as possible as to what is the right way of doing it. One of the things, however, about the simulation which should be brought out because I think it may prove to be significant; it may be something, it's not an irrevocable lack, it can be put in later, is that at the moment it does not have a coning model for the wells. And I have agreed with Mr. -- Dr. VanPoollen, it would seem at this time, that there's probably no reason to work it in. The reason for this is that all the simulations of reservoirs -- of well behavior today and all the observations in the field suggest that there is a shale pretty close above the upper perforation of the wells. Under these conditions you're not going to get any coning. But it also means that you're not going to get direct gravity drainage, although as you heard yesterday, the shales are leaky, we don't know exactly yet until there is more experience accumulated, leaky to what, certainly to gas, at the moment, you'd have to say that, but whether they will leak oil at the same rate they leak gas is something that will still have to be determined. So, what we do see and I really am sorry that this hearing has come now, if it came two months later we would be able to say things with a little more definitiveness, but what we are supposedly seeing now. is we are seeing the shales there, we are seeing have to realize there is going to be interference with a

unmitigated gravity drainage. In general, I would have to say this is going to detract from gravity drainage, there's now two ways about that, whether they will be compensating things and I would like you to note that the compensating things that were suggested yesterday would be water flooding, and if you didn't get the gravity drainage we get with water, but that's important, get it with water flooding, and we have to take in to account when will the water flooding be coming on and what will be the effect of the shrinkage of the oil and the gas liberation by the time water flood comes on. In other words, the situation is building for me that water flooding, although a questionable thing two years ago, is more and more looming on the horizon as something that Prudhoe Bay will need and if it needs it, the sooner it gets it the better.

BY: MR. PARR

Did you by -- instead of water flooding, Dr. Doscher, mean that pressure maintenance by (indisc - simultaneous speech)

BY: DR. DOSCHER

No, because, no -- the pressure has been going down now, by the time we get around to it, it will be water flooding now.

BY: MR. PARR

Okay, thank you.

BY: DR. DOSCHER

We've got another....

BY: MR. PARR

I just wanted to make sure that was deliberately chosen.

BY: MR. MILES

That decrease in pressure though is -- is not unusual.

BY: DR. DOSCHER

Now, let's talk about the decrease in pressure. This is a very -- for me to sit her and say the pressure is going faster or slower is very difficult. I am not -- I don't spend the time to follow the data week by week. I didn't think that was my job. I only recently, incidentally, got permission to view the data, pressure data in the field. Ah... when I asked it was given, but this only happened a month ago. Now, talking in pressure decline, in terms of absolute numbers, at this point, is a little questionable. You see, I was retained, I believe, to look at the fine points of the reservoir behavior, not to see whether it was qualitatively behaving as predicted, but is there something very, very small here that may be indicating some problems. Now, I think there is something here that's indicating some problems in terms of pressure behavior. First of all, yesterday we saw what the GOR is and it was said to be a little bit above the solution gas ratio, but then it depends upon what you mean by a little bit above. The number I saw on the chart was 900 cubic feet per barrel. This is about 20% greater than the solution gas ratio. This is about 20% greater than that predicted in the Exxon runs, the numerical simulation runs, which were distributed at the hearing in May '77 at

Anchorage. Now is 150 significant? I think it is, particularly if the solution gas ratio is 750, an average of 900, although you say, "Well, it's -- it's only 150, its 20%," but you don't get up to 900 on the predicted Exxon runs or even on VanPoollen runs, I don't think we can use the old VanPoollen model here as any reference because it was a 2-D Model, so I think the reference has to be to the 3-D runs. You don't get up to 900 for four or five years. Now, the pressure decline, the numbers that were quoted yesterday were six hundred and thirty million -- three million barrels in 171 psi. That's .28 psi per million barrels. Again, looking at the xerox copies of the Exxon report and there has to be some error there, but still looking at all thirteen runs and taking average figures, it seems that it should be closer to two tenths, a difference of about 50%. Now, I think that's -- that's something significant because you're in the early life of the reservoir and you have to look at these fine points. I hope I'm wrong, but I'd stop looking at why this difference is being-- occuring.

BY: MR. CHATTERTON

Before you get too far away from that Todd, let me explore something with you. This is...ah...normally a 440 foot thick oil column...ah..what's the solution gas-oil ratio -- is there any variance in the solution gas-oil ratio between the ...

BY: DR. DOSCHER

...Oh yes, yes...

BY: MR. CHATTERTON

...top of the column and the bottom and would you give me those numbers?

BY: DR. DOSCHER

Oh, it varies from 700 to 900.

BY: MR. CHATTERTON

Thank you and what was the average GOR that was reported yesterday?

BY: DR. DOSCHER

900.

BY: MR. CHATTERTON

An you gave us percentages -- and you gave us some percentage numbers here, what were you comparing?

BY: DR. DOSCHER

I'm comparing to the 750 average that is used in the simulation studies and the projections of the field behavior.

BY: MR. CHATTERTON

Granted, and my point being this Todd, most of the withdrawals are from the lower section of the oil zone, the lithologic units in the lower section of the oil zone where you have the...

BY: DR. DOSCHER

...then I'd expect it to be less than 900.

BY: MR. CHATTERTON

You'd have to expect it to be somewhat less.

BY: DR. DOSCHER

Less than 900. Particularly since most of the production, I believe, is from the better, I forget how the intervals are named from the interval that has the least shale, and so..ah..I think we should be seeing something so that it is on the average, but less than 900. In other words, it is 900 already. This bothers me, that it should be even at the upper end of the ratio.

BY: MR. CHATTERTON

Thank you.

BY: DR. DOSCHER

And the pressure decline also bothers me because it is just that much over what was projected..ah.. I want to know why. Now, we've heard of the wells over on the eastside, those lined out in red, these are -- I mean they're four, six thousand GOR, many -- some, I don't know how many, are shut in and if you shut them in and open, the GOR goes back up. In other words, you don't seem to be able to heal it for long. Ah...now, there -- this is the shaley part of the field, it's at the edge of the field and you can say, "Well, the gas is coming out, it's close to the gas cap, it's channeling under the shale," but you see this may -- if this is real, this may happen a little further down, a year or two from now. In other words, it's the suggestion that something could happen here which has not been anticipated in the model run. Now,

it's -- you know, we're not going to change this overnight. These things are going to happen, but one thing that's suggested to me is that until we understand why this is going to happen, all I can say is that my original conclusion is not to commit the gas until we get a better handle on this, is a little strengthened, not to commit to higher production ratios until we get a little better handle on it is somewhat strengthened, because again we're going to have problem with our own model, the State's model, in making adequate rate analyses or analyses of rate, because of the absence of a coning model and insofar as this may be important, we're not prepared at the moment to do it and this is no oversight, this is a question of what it takes to build a coning model and whether it's absolutely necessary to make our checks at this point, noted, in order to start being able to predict. It's a very, very complicated problem. So, there's no faults involved here, it's just the way things are working out. Now, there are a couple of other things then that since I haven't had a chance to talk to you since the...ah..in any great length, until since the hearings were held in Washington and since the transactions of the hearings have come out, there are a couple of things I'd like to bring to your attention. One is we were criticized because our proposal to reinject the gas into the reservoir was said to take a lot of gas, a lot of the natural resource we had. Well, we didn't make a

calculation before because I knew what it was and didn't think it worth mentioning, but at this time I will mention it that in fifteen years based on the VanPoollen models, and again these are -- you know -- they have to be confirmed by the 3-D, we would have to reinject about 15 trillion cubic feet of gas in 15 years if we did not sell it. It would take one and a half trillion cubic feet as fuel to compress this gas and return it to the reservoir. Now, this one and a half trillion is less than 4% of the total and if you're going to produce gas after that time, this difference of 4% is just not going to effect the ultimate recovery of gas from the reservoir. So, the matter of wasting energy or using energy in an irrevocable way to return the gas to the reservoir, I don't believe is a valid point. Another point which we were fairly well criticized for and it wasn't something we said should be done, but we posed the question in our report, should consideration be given to using the crude oil line for the two phase flow of gas and oil at that time some fifteen years away when the oil production might have dropped to five hundred thousand barrels and of course continue to do so, we said, should consideration be given. Well, we heard everything that -- from -- that this was a mind-boggling idea and then Exxon subsequently did a very professional job, a good job, of showing that with conventional technology this was -- just

not to be considered. But our point is that we have to look for unconventional technology in this time when energy is so important to the nation. We can keep throwing out ideas, could you transmit it as a foam, and then you'd avoid many of the problems that were raised as problems in transmitting two phases, but there'd be problems here. I don't know if you can make a foam. These are things though, that when you start crashing a subject, what can you do to save money, what can you do for a more efficient utilization of the capital and energy resources of the nation, one might come up with some ideas. For example, right now, the pipeline is testing a friction reducing agent. The friction reducing agent was not developed by the pipeline people. It was developed by a small competitor. The times require a tremendous effort in order to save both our energy and our capital. Now, finally just in ending, there is no question that any decision not to sell gas is going to be subject to the most -- well, it's going to be subject to a lot of criticism by many, many different groups of people. We say that this might be the best way of running the reservoir, we also point this out, that the gas in Prudhoe is only 5% of what is available to America today, only 5%. Whereas the crude oil in Prudhoe Bay is one-third of what is presently available to the nation. Now, under those conditions -- which should we conserve more, which should we worry about more. Will rushing that 5%

to market, substantially change the welfare of the State or of the nation. Will conserving a billion or two billion barrels of oil in Prudhoe Bay substantially aid the nation and the State. These are questions that have to be considered and I trust that with the work that the VanPoollen and Associates are doing and the work you're doing in-house, that you'll reach the right answers.

BY: MR. MILES

Thank you very much Doctor. We appreciate the presentation. Representative Hayes

BY: MR. HAYES

Thank you, Chairman Miles. Yesterday I asked the question of Dr. VanPoollen was if he would be able today to respond to any of the points Dr. Doscher might make.

I wonder if..ah..it would be appropriate at this time to ask Dr. VanPoollen if he would like to make any rebuttal or any -- or did you have that in mind for later?

BY: MR. MILES

I don't think that would be appropriate at this time Joe -- I'd rather have questions directed to Dr. Doscher, we don't want to get into a pingpong match here. If there're questions of Dr. Doscher, fine, if..ah.. Dr. VanPoollen thinks that -- you know -- it's appropriate to respond, we'd certainly make that a available opportunity and then we will make it available to Dr. Doscher and whoever the hell else wants to respond.

BY: MR. Hayes

There have been some -- there have been some comments made by Dr. Doscher that are -- you know -- are practically 180 degrees to some of...

BY: DR. DOSCHER

Oh, I don't think so.

BY: MR. MILES

Well, let's -- let's ask the direct questions to Dr. Doscher first.

BY: MR. CHATTERTON

I think so too.

BY: MR. MILES

Mr. Chatterton.

BY: MR. CHATTERTON

Thank you Mr. Chairman. Doctor, really the impact of your direct testimony is..ah..and I think it's concurrent with your studies and everything else that you've done, has been directed more against gas sales, the appropriateness of it, is it also -- I read in the newspapers..ah..questions about regardless of whether or not there are gas sales of crude oil recovery up there..ah.. and particularly the matter of rate sensitivity of the ultimate recovery to withdrawal rates.. ah..you were talking about a natural water flood, I guess there would be no question but what ultimate recovery would be, or is there a question sensitive to withdrawal rates in

the case of a natural water flood. In other words, what happens if you..ah..withdraw black oil faster than the influx of the natural aquifer?

BY: DR. DOSCHER

Oh, you won't sustain the pressure and your recovery will go down.

BY: MR. CHATTERTON

Okay, so in a reservoir of that type, why definitely -- why.. ah..withdrawal is -- recovery is rate sensitive?

BY: DR. DOSCHER

Absolutely.

BY: MR. CHATTERTON

Now at Prudhoe Bay -- why -- what I've read and I think you mentioned it also, we have seen no evidence of natural..ah.. action that we hear (indisc) aquifer, right?

BY: DR. DOSCHER

That's right, that's right, oh yes. Sadly, it's (indisc)

BY: MR. CHATTERTON

In fact, are we not seeing basically..ah..solution gas drive and gas at this point in time anyways, solution gas drive and gas cap expansion as a primary measure.

BY: DR. DOSCHER

That's right.

BY: MR. CHATTERTON

How do reservoirs and under that type of a drive..ah..react

to rate sensitivity?

BY: DR. DOSCHER

Oh, gas cap expansion is notoriously as the prime -- as the prime mechanism which contributes to rate sensitivity because the depletion of oil in the gas cap area is a very rate sensitive phenomena because it depends on the rate at which the oil will drain down the column which has very little to do with what else your doing. So, gas drainage -- oil drainage in a gas column is very rate sensitive.

BY: MR. CHATTERTON

I'm not sure I understand.

BY: DR. DOSCHER

Well, you see, up above here you have oil, you start out with oil in top, okay? And your gas is going to come down penetrating that oil zone leaving behind some oil residual saturation, okay? The attainment of the lowest equilibrium saturation of oil is a rate sensitive phenomena.

BY: MR. CHATTERTON

Due to the ability of it (indisc - simultaneous speech)

BY: DR. DOSCHER

...of the oil itself to drain down. It has nothing -- it doesn't care what's going on down below, you see. If you start ripping and taking it out too fast below the gas is going to finger down and leave a lot of oil behind. The drainage of oil in the gas environment is terribly rate sensitiv

BY: MR. CHATTERTON

Alright, I guess, if you're under a gas cap expansion drive where it is coming down uniformly, why then probably you're within in your efficient rate production of black oil. In other words....

BY: DR. DOSCHER

I bet -- I'm not sure I understand.

BY: MR. CHATTERTON

Alright, supposing we have, as we have up there now, we have an expanding gas cap and we're withdrawing black oil. Alright, if that expanding gas cap is coming down sort of uniformly, not tonguing, not fingering, so forth and so on, would that be suggestive that we're within the envelope....

BY: DR. DOSCHER

Well no, we don't know that. This is one of the -- this is explicitly the thing that the State is setting about or has asked the operators to make surveillance of the gas-oil contact to actually measure that. You see, because depending on how the gas-oil contact falls, if you finding it falling faster than you anticipated, it means your leaving more oil behind.

BY: MR. CHATTERTON

I understand.

BY: MR. CHATTERON

Okay. So we don't know that this is one of the things that hopefully we will learn and one of -- that is one of the main

things we suggested two years ago that we needed to know before we could commit the gas sales.

BY: MR. CHATTERTON

Right, and at that point -- and at this point in time we do not have the knowledge or the equipment to say whether....

BY: DR. DOSCHER

I don't know that, I have not been exposed to the results of that test. I don't know that. I presume this would be..ah.. made available at the hearing that was, I believe, was scheduled for June or so, and that is now being deferred to fall.

BY: MR. CHATTERTON

But perhaps it's premature to cry foul at this point in time (indisc - simultaneous speech)

BY: DR. DOSCHER

Yea, I -- just as I say, two months from now we could be -- you know -- there would be a lot less suggestion and a little more information.

BY: MR. CHATTERTON

Thank you. Thank you Mr. Chairman.

BY: MR. MILES

Mr. Rogers.

BY: MR. ROGERS

Yes, Dr. Doscher, you've talked a lot about ultimate recovery of crude oil and particularly said since we have a greater

percentage of U.S. domestic oil reserves and gas reserves, that we should sort of concentrate, I guess, on ultimate recovery of crude oil, but is the State's interest, do you think, then on the crude oil recovery on the total hydrocarbon recovery.

BY: DR. DOSCHER

Oh well, you will not interfer with ultimate gas recovery no matter what you do. You see, when you finish taking all the oil out you just open the valve and the gas will come out. I mean, you'll just blow it, what we'd say would be a volumetric gas reservoir, which means you just have a can of -- filled with gas, open it up and the gas just comes out. So that's why even using up...

BY: MR. ROGERS

So you think that 1.5 trillion cubic feet loss is negligible.

BY: DR. DOSCHER

Negligible, because you -- you stand to get 75 or 80% of the gas in the gas cap at that time without any sweat at all. So, when I say if you improve the recovery of oil then automatically regardless of time, I mean, taking the time value out, you're going to get maximized BTU then.

BY: MR. MILES

Doctor, go to the question of shale, I find the more I hear about shale the less I understand it. It is my understanding of yesterday that the -- we can't tell right now whether or

not the presence of shale is going to be a serious problem.

I understood you say that it will detract -- from the gravity drain.

BY: DR. DOSCHER

I believe that was said yesterday too. I think if you look back it was said that it would certainly detract from gravity drainage, but then the statement was also made, you can check the minutes, that it would also help -- help you sweep the reservoir with water because you would have boundaries into which the water could be channeled.

BY: MR. MILES

Okay, so we can't -- we can't necessary say that, I'm sorry I can't discuss these things in the technical level with you, but we can't say that shales are bad for ....

BY: DR. DOSCHER

Oh they're bad, they're bad for gravity drainage recovery.

BY: MR. MILES

Well, okay.

BY: DR. DOSCHER

Okay? Now, they may be good for water flooding provided you water flood early enough. Okay? If you wait until the oil has shrunk..ah..due to its abnormal -- very high pressure decline -- I'm sure they're not going to wait that -- I mean, so it shrinks that bad. But..ah..if you wait until it shrinks..ah..if you wait until the pressure is released, if

you wait until you get high gas saturation in there, then water flooding will not be as efficient as if you start early.

BY: MR. MILES

Well I guess, guess what I'm asking is, I understand in the first vanPoolen runs the existence of the shales wasn't a fact that if it was plugged into the computer, they are now being plugged into the computer because they're -- they're obviously a very real factor. The question that I want to know is can we say that the presence of these is going to reduce recovery?

BY: DR. DOSCHER

I would venture the guess that in the absence of water flooding -- in the absence of water flooding it will reduce recovery compared to the absence of water flooding before. Okay?

BY: MR. MILES

Okay. How about if we go in after five years of production and water flood?

BY: DR. DOSCHER

Ah..you may get more -- you may get more as compared to not doing a water flood at all. Okay? In other words -- in other words you're going to -- as soon as you say I've got to water flood, you're in a different ball park, but if you go back and compare the situation without water flooding then

the shales, in my mind, have -- will cause a drop in recovery.

BY: MR. MILES

We in essence have two different ball games.

BY: DR. DOSCHER

That's right.

BY: MR. MILES

Thank you. Mr. Chatterton.

BY: MR. CHATTERON

Anybody else first. Okay, Todd, let's talk about water flooding for a minute. I've had a little experience in producing operations and one thing I always feared was getting increased water cuts in my producing column because it took more energy to lift the column, to get my black oil, and..ah.. I guess that's a paranoia with me more -- I hate to..ah.. willy nilly -- see, put water into a reservoir. You even spoke of the fact that..ah..of pilot floods and don't you sort of really want to know the geometry and just how things are going before you start...

BY: DR. DOSCHER

I want to know the relevant injectivity. That's a pretty easy thing, I want to know the compatibility of the water, I can do that on paper in a half hour. Now, breakthrough, see you're talking about early water breakthrough. Now where -- how can we get that? Now, let's assume you have a uniform

reservoir, okay? The only time you'll get early breakthrough in a uniform reservoir is if you have a viscous oil, which we do not have at Prudhoe Bay....

BY: MR. CHATTERTON

Under pressure?

BY: DR. DOSCHER

....mind you, that as the pressure goes down and gas comes out of solution, the viscosity will start going up. Now never going to go very high, but we do change it from something which is delightfully favorable viscosity ratio to something that's not quite favorable, okay? If you wait for pressure to go down. But now, in Prudhoe Bay I would expect water fingering or water channelling to occur only from heterogeneity in lithology. In other words, a very gross change in permeability between adjacent strata or a foot apart. Ah..this has to be known..ah..it can be if you find that it occurs, it can be avoided to some extent not completely. Ah.. there are all sorts of remedies which we can call on for close in support of..ah..channelling, like channel blocks and silica and even cement. But if it is very bad we cannot stop it. In other words, if you had a gross heterogeneity like a fracture, we cannot stop it, but if we have that, this reservoir is going to suffer even from gas expansion because once the gas sees that it's going to channel through. I hope we don't have it, there is nothing to suggest we have

such gross heterogeneities here.

BY: MR. CHATTERTON

If I may Mr. Chairman, I can always get a better feel and qualify and quantify things if I work from the extremes. So, I'll ask you this question and it's an extreme question, from day one or year one after production is started and we know nothing more than the oil is coming out of the ground, so to speak, to go willy-nilly blindly for the full scale pressure maintenance by water injectivity, is it conceivable that you might cause irreparable harm to ultimate recovery?

BY: DR. DOSCHER

Ah..it's conceivable, but I think the level of expertise in the -- among the operators and among the State is such that this probably would not happen. It's a remote possibility, I think, given the expertise that's here.

BY: MR. CHATTERTON

But, would you share with me that in many things, the assimily of this, you learn to crawl before you walk.

BY: DR. DOSCHER

Well, yea, except we've been -- you know -- we've been at this business for a long time. Now,-- you know -- we're not going to water flood this within a year anymore, okay? So, and I'm not the one to say we did something, I don't believe in looking back, okay? It happens, it happens, for any reason.

But I do believe in looking forward and if the evidence begins to accumulate, as I think it is, that water flooding seems to be indicative for the -- indicated as a need for the reservoir we'd better start thinking of it very seriously.

BY: MR. CHATTERTON

For the last question -- which is really, cause I sure want to see how you feel about it. We've talked about pressure maintenance by water injection, we've talked about water flooding, we already know that we haven't maintained pressure because we've lost our material ballast to this point. Can we not over inject once water -- once we start pouring water into the ground, can't we over exceed our withdrawal rates and catch up, build our pressure up.

BY: DR. DOSCHER

You can catch up but never 100%. Now, again this depends on the particular -- you never get 100%.

BY: MR. CHATTERTON

Understood (indisc - simultaneous speech)

BY: DR. DOSCHER

How close you come depends on the particular reservoir and the timing that's involved. As I said, the -- again you use an extreme case, I'm using an extreme case. If you let the pressure go down, you have enough shrinkage and you establish a high gas (indisc) you may start channelling a lot of water to the gas, okay? So, I don't think that we'd

ever go that far here but -- talking about extreme. We'll -- we'll catch up a way whether it's 100% I couldn't tell you -- I mean, we'll get pretty close. The faster we get there the better it is, if we need it.

BY: MR. CHATTERTON

Thank you. Thank you Mr. Chairman.

BY: MR. MILES

Mr. McKinnon.

BY: MR. McKINNON

A few minutes ago you used the phrase "if water flooding is indicated"....

BY: DR. DOSCHER

Well, I believe it's indicated already, okay?

BY: MR. McKINNON

....and Dr. vanPoollen believes it's indicated?

BY: DR. DOSCHER

I think -- well, I'm not going to -- if he says that, that's great.

BY: MR. McKINNON

He makes that recommendation in his study two years ago. and apparently the companies are applying for permits and I would assume that indicates the company believes water flooding if necessary. The question is when is it necessary?

BY: DR. DOSCHER

Well, if it's necessary then at this point, the faster,

because you can't put water in that ground for another three years. Okay? Even if you had the pumps there today probably because the piping and everything and the treating plant and the stabilization system and..ah..at that time we will have produced 25-30% of the reservoir. That's a lot of oil.

BY: MR. McKINNON

At that time, I assume, we'll have enough production history to be able to tell (indisc - simultaneous speech)

BY: DR. DOSCHER

....you'd know exactly where to go.

BY: MR. McKINNON

So if everybody agrees that water flooding is necessary, it would seem logical to go ahead and start with facilities that could be constructed at this point.

BY: DR. DOSCHER

This is up to the Oil and Gas Conservation Commission to study and all I can say is that this is what it seems to me. Their conclusions agree, I -- that's great.

BY: MR. McKINNON

At what point is it too late to start water flooding?

BY: DR. DOSCHER

I'd say if you started twenty years from now it's too late, okay? Now where in between I don't know.

BY: MR. McKINNON

Well, Chat's - Chat's talking about willy-nilly which I

assume means four or five years into production.

BY: DR. DOSCHER

No, I didn't know...

BY: MR. McKINNON

You said a year or...

BY: MR. CHATTERTON

No, no, no I meant we -- blindly just pour water in like a year ago now start pouring water in, is what I was trying to emphasize.

BY: MR. McKINNON

When is it too late economically for the companies?

BY: DR. DOSCHER

Well, I couldn't tell you, you'd have to ask them what their rate of return is expected. But I would think -- I mean, I just -- you don't want to wait until you're just producing a -- look it -- if you injected water so late that you're only producing 100,000 barrels a day, I don't think there is anyway, even with zero discount rate, that you could make out with 100,000 barrels of oil a day. In other words, you have to produce it so that you're still getting oil where everything else can carry itself, where you can afford the maintenance in the field and the pipeline burden.

BY: MR. McKINNON

Water flooding is going to increase ultimate recovery, why wouldn't the companies want to go ahead and do it?

There is no page 197 and a discontinuity is evident.

nk

at..ah..I believe, the reservoir -- the formation volumn factor is about 1.4 which means if you took all the gas out, zero pressure, the oil would shrink 40%. Now if the oil shrinks it leaves gas, so when you put the water in, the water sees this very mobile free-flowing gas and it kicks the gas out and leaves the oil behind, okay? That's the most damaging thing that can happen.

BY: MR. McKINNON

When you -- when you start putting water in and you've delayed it for a period of time and you start building the pressure back up, how much of that -- or what's the difference, let's say from putting it in year four and year eight?

BY: DR. DOSCHER

Well, there are sometimes you never catch up with pressure. I mean there are oodles of examples down along the gulf coast where -- you've rather a small reservoirs, where you're just -- where you're taking the oil out so fast you just can't put the water in that fast. I mean, we say you play catch up but this catch up means you're really going to have to whale the water in which makes the problem a little more difficult because the faster you try to put water in, the more problems you have in overall integrity.

So, there has to be an optimum time. Certainly you can't do it at zero -- at time zero on terms of a shear economics, you can't wait twenty years in terms of what you can get out

of the reservoir. But, I would say that we are coming close to the time when..ah..any -- my own feeling is any further delay is not warranted.

BY: MR. MILES

Ah.. Mr. Parr is next, I think.

BY: MR. PARR

Very simple question, Dr. Doscher, for the benefit of us laymen who don't understand all this.

In your considered judgment, there should be no gas sold until the water injection system for pressure maintenance is in place and ready to operate.

BY: DR. DOSCHER

That's right.

BY: MR. MILES

Mr. Rogers.

BY: MR. ROGERS

Yea. Going back to this -- I was asking you about ultimate hydrocarbon -- recovery, but there is two ways to measure that, one's in volume and one's in dollars, and given that..ah.. there's a time value to the dollars but there may or may not be a time value to the quantity..ah..should we be -- in your opinion, should we be looking at..ah..trying to go for the highest ultimate quantity or the highest dollar return.

BY: DR. DOSCHER

Well, this is a question that -- you know -- this is a

stateside question. Certainly, I would recommend that you want the maximum return to the State; as a citizen of the United States I'd want you to temper that with some thought of the maximum BTU. Now, I think, considering the increase in crude oil price and gas price, inevitable increase, that you don't have to worry about some delay as losing your investment since it doesn't -- you don't put in much capital.

BY: MR. ROGERS

Because the State's discount rate, whatever it is, is probably lower than the inflation rate....

BY: DR. DOSCHER

That's right, that's right. And don't have any question about the price of oil and gas going up. When I two years ago suggested $20 a barrel, I'm off by a couple of dollars, it's above $20. And, Mr. Schlessinger, yesterday suggested that $40 a barrel in uninflated costs in five or six years. Now, the reason for this is simple, it's not because the OPEC is greedy, and they are greedy, and everybody would be, but we're running out of it. See this, this is the fact. We have reached peak production in the world, not now, maybe tomorrow. If you find something in Prudhoe Bay, may delay it a year or two, but basically, the areas we can look and search for oil we are running out of them. We'll need alternates well before you go -- you finish producing at Prudhoe Bay. So, your value of the goods is just going up.

BY: MR. ROGERS

For that reason you'd suggest that the State pursue a course of..ah..ultimate hydrocarbon recovery rather than, than..ah.. their current guess of what the ultimate dollar recovery is.

BY: DR. DOSCHER

I would, I would tend to opt in this direction.

BY: MR. ROGERS

Thank you.

BY: MR. MILES

I think Mr. Hayes is next.

BY: MR. HAYES

Dr. Doscher..ah..yesterday Mr. Hamilton and Mr. Green discussed ..ah..water flooding and they were talking about their -- their plan to ..ah.. as I understood it to wait until such time as the field produced about 100,000 barrels of water a day as a byproduct and then reinject that. One of the reasons they stated for doing that was because of the capatibility of the residue water with the water that was already in the field. The comment you made a little -- a few minutes ago, talking of -- about how many -- how many years involved accomplishing water injection, you mentioned a treatment plant and pipe and that sort of thing, I inferred from that that you're talking about a different type of water injection, perhaps sea water -- my question is, is that what you're talking about...

BY: DR. DOSCHER

Yes.

BY: MR. HAYES

....and the second part of my question is, do you agree with the..ah..plan as outlined by..ah..Mr. Hamilton and Mr. Green as far as the proper way to ..ah.. sort of, ease into the water flooding program?

BY: DR. DOSCHER

I would..ah..first of all I'd like to say that yesterday they -- it was said that eventually you would use sea water, so basically, we are all talking about the same thing eventually. Now, the -- I don't want to -- I'm not going to say I agree or disagree with the Board, I would put it this way, that I would like to -- or there are some folks around who could convey to them..ah..possibly ideas that are at variance with their -- what they suggested here which would speed things up. Now, I for example, believe that you could test compatibility in a test tube with a chemical analysis in an hour. The data is available. Now, again, this may be just some oversight or of some problem that I'm not aware of, but basically, I think, compatibility is easily determined. Now, the need for 100,000 barrels, I believe, they were thinking that they would see something in the reservoir behavior, in the reservoir behavior and my point is, I really don't think you'd see anything in reservoir behavior unless you had a very --

unless you'd drill a lot of core holes to see where the water had gone. and where it had displaced or had a lot of close-in wells where you could see the response. This is generally difficult to do because when you put water in you have a high pressure right near that well bore and that water just skirts all over, so it's very difficult to control, so from a reservoir standpoint you don't learn too much. I think about the only thing you can learn is injectivity, knowing injectivity, the need for it, you start in a fairly -- well, you start in a big part of the field -- in a part of the field on a fairly good size scale though, not just one or two wells where you think you need it most, then you build from that point. Now, again, I'm not saying I disagree it because I would have to see the logistic and so forth and I would be one for saying, let's get the 100,000 barrels by going into shallow aquifers if we could find those in order to hasten the definition of what the needs are.

BY: MR. MILES

Doctor, you mentioned the proposed increase to..ah.. a million five barrels a day in your paper, but you don't, but you don't get into it too much, what -- what impact or what effect on ultimate recovery ..ah.. will this -- may this have and this increase in production, how will ..ah..just how will that..ah..how may that effect the ultimate recovery?

BY: DR. DOSCHER

Again, I, of course, cannot give you a firm answer but ..ah..

I'm willing to summize.

BY: MR. MILES

Well, we're going to have to make a decision on the -- Nobody's firm answer, because (indics) not going to be there.

BY: DR. DOSCHER

I'm concerned about the fact that in the..ah..one side of the field we have high GOR's that won't go away. I'm concerned that this may spread on us if we start because you recall it was brought out yesterday, very clear, that coning or gas breakout is occasioned by high rates and large pressure draw-downs so that if higher rates are instituted and this condition spreads, we may find more and more of the field is going to high GOR's. So, again, because I don't know different I'd say be a little cautious, we'll let 300,000 barrels mean that much to you or the operators, this is a question that the commission has to decide. If it's going to mean the question of life or death or whether..ah..cash flow is viable or not, you'd tend to nudge it the other way, but as far as the needs of the United States, I think another 300,000 barrels isn't going to change our basic conditions and..ah..matter of fact, I feel the sooner we start living without that 300,000 barrels the better off we are because we're not finding a replacement for it.

BY: MR. MILES

Thank you. Chat.

BY: MR. CHATTERTON

Thank you Mr. Chairman, I've got a series of three unrelated questions, if you'd give me the latitude, I'll try and proceed. One, Dr. Doscher, in response to Representative Parr's question you said, in effect, that no gas should be sold until injection is in place and ready to operate..ah..and you gave him an answer to the affirmative.

BY: DR. DOSCHER

That's correct.

BY: MR. CHATTERTON

I would like to follow up on that question a little bit. Do we know that even with these injection facilities in a position to operate that it still would be wise?

BY: DR. DOSCHER

Oh -- you're right on. When I said ready to operate, I meant that. ah..we knew we could put the water in because there may be a significant time, even with the water at the well head before the water starts going in a uniform way.

Now, I hope that's not going to be long, I hope that the injectivity tests which are being done now will teach us what we need to know so that when that time occurs there won't be a delay, but basically you're right. As a matter of fact, you might even say that you want to wait until the pressure builds up to some point in the reservoir. Again, I have to say we'll have to wait until we see the 3-D studies to ascertain this.

BY: MR. CHATTERTON

Alright, I'll try to clarify where I was going to get a response to, even then, do we know whether we'll suffer ultimate loss of recovery of black oil by permitting gas sales?

BY: DR. DOSCHER

Well, I hope the 3-D studies will have informed us.

BY: MR. CHATTERTON

Yea, I know, I know, I know, but it may show that you might not even want to do it....

BY: DR. DOSCHER

....You're absolutely right.

BY: MR. CHATTERON

....I didn't want a closed answer to....

BY: DR. DOSCHER

You're absolutely right..ah..I beg -- this goes back to our study, basically, of..ah..not -- but the runs we made with the vanPoollen and Associates model which indicated that water flooding and no gas sales gives you all that much more oil.

BY: MR. CHATTERTON

Thank you. Okay, and I said next unrelated question, water flooding and I'm using your definition of water flooding, given that that became sort of a field wide technique 3-1/2 decades ago, where was water flooding started, it wasn't -- first -- what types of reservoirs, weren't they virtually

depleted as far as primary recovery is concerned?

BY: DR. DOSCHER

No, the first reservoirs were..ah.. not depleted at all, they were leaks in the casing in Pennsylvania in 1890.

BY: MR. CHATTERTON

Well -- well then -- let's say man -- well it's man made too, on purpose by man....

BY: DR. DOSCHER

On purpose by man, you're right, that they were depleted....

BY: MR. CHATTERON

3-1/2 -- okay, they were depleted reservoirs and basically our history has improved the recoveries -- has been our long standing histories, anyway, has been from depleted reservoirs and now we're boning up on the fact, well, maybe we should have -- we should start early in the game.

BY: DR. DOSCHER

Again, I could point to say..ah..a couple of the reservoirs in the North Sea -- or you put water in or the operators putting water in very early and in Alberta you'll find several reservoirs where..ah..water goes in just about from day one, but there they have a experience level....

BY: MR. CHATTERTON

....but we don't have too much field history in back of us, when I say too much....

BY: DR. DOSCHER

You're right.

BY: MR. CHATTERTON

Okay, in those cases. Let me ask you one other question.

BY: DR. DOSCHER

Except in natural water drive we have....

BY: MR. CHATTERON

Oh, I understand, right. One other unrelated question, you gave -- you expressed concern with the rate sensitivy between 1.2 and 1.5 million barrels a day, and you were alluding to the fact that we had some gas tongueing and/or coning, whatever. Now, given that that gas coning and so forth and so on, or tongueing occurred -- it occurred with X number of withdrawal points, now -- we now have many more withdrawal points in the reservoir to where possibly even the rate of withdrawal from any single straw is dropping off, doesn't that not sort of mitigate your concern?

BY: DR. DOSCHER

A little bit..ah..but again, without knowing the exact nature of the coning, if it is coning or tongueing..ah..basically you're right. The more drainage points I have the less will the problems be.

BY: MR. CHATTERTON

And were gaining...

BY: DR. DOSCHER

So, I'll just stop and say this....

BY: MR. CHATTERTON

....and we're gaining about six or seven drainage points per

month up there.

BY: DR. DOSCHER

Right, but on pretty big spacing. You see, I don't know at this time whether it's a spacing phenomena or just what because again -- I mean, our control is small again. Okay, and on the east side the thing of concern is we have -- that's where we have the most wells, where we have the most coning.

BY: MR. CHATTERTON

I guess what I'm saying is, do you agree with me we'd be on very thin ice to -- with this expanding number at the rate of six a month, let's say withdrawal points being drilled in and put on production. Why, we're on thin ice if we pound the table and say you can't go to 1.5 barrels....

BY: DR. DOSCHER

....Oh, there's no question of that, no, no question of that.

BY: MR. CHATTERTON

Thank you.

BY: DR. DOSCHER

And as I've said, I had no ice at all, I have only trends that I'm extracting.

BY: MR. CHATTETON

Yea, alright. Thank you, thank you Mr. Chairman.

BY: MR. MILES

Mr. Rogers.

BY: MR. ROGERS

..Ah..maybe another no ice question ..ah.. follow up on that

and what Chairman Miles said, if we're three years from water flooding..ah..and if you think it may -- that the increase of 300,000 barrels a day up to 1.5 could effect ultimate recovery..ah..what would -- what do you think the effect would be if production were held to a slower rate than the current 1.2, at either 1.0 or 800,000 or something given as that....

BY: DR. DOSCHER

....isn't that what it is? We have no evidence to indicate any serious negative effect. Maybe there will be after he does some more work.

BY: MR. ROGERS

....Is there significant positive effect? Alright (indisc - simultaneous speech)

BY: DR. DOSCHER

No significant -- we have no evidence to believe that there would be a significant positive effect..ah..at this time.

BY: MR. ROGERS

Thank you.

BY: MR. MILES

Mr. Parr

BY: MR. PARR

Yeah, Mr. Chairman. Ah.. Dr. Doscher, you said in Alberta they -- sometimes they bring the water in on day one, right? Now, have they done that much advance research on those fields

that they are -- they know the reservoir that intimately that know that the water flooding is a desirable thing, at day one that, as we've been told, that there are dangers in water flooding if you don't know -- you may be doing yourself harm rather than good. How do they know that day one bit.

BY: DR. DOSCHER

I think the dangers have been a little exaggerated. As I walk through with some of the answers with Representative Chatterton..ah..one of the most important dangers was this question of the water channelling through. Well, you more or less learn about the possibility of these channels in your drilling program, whether your drilling mud gets lost. In other words, you know a lot of this by the time you finish drilling the well. You know a lot of this from the viscosity how thick the oil is. So, in general, I'm not -- there are dangers but I don't make as much of them, I thought that with my answers to Mr. Chatterton that came out. I don't make that much of it.

BY: MR. PARR

Well, to come back into my question, did the people in Alberta, where you're doing this on day one, know their reservoir that intimately before they started that they could do that?

BY: DR. DOSCHER

Yep, they do that.

BY: MR. PARR

Now we don't have anywhere close to that kind of knowledge at Prudhoe Bay.

BY: DR. DOSCHER

It's pretty close, it's pretty close. In other words, I think there's just a little -- you just need the operators -- possibly have to do a little more -- your injectivity test will tell you. The injectivity test will tell you whether there is -- and profile test, where you go in after the injection and see where the water is going. You can learn fairly quickly whether there are some sands that take most of the water and that's the danger. And you can learn that pretty directly.

BY: MR. PARR

Well, let me ask you the other question on -- why wouldn't we have..ah..done all those tests before we started exploiting the reservoir at all here in Prudhoe Bay. If it is as you say -- make it sound rather simple injectivity test and it doesn't (indisc - simultaneous speech)

BY: DR. DOSCHER

Alright, at the time of our first -- at the time of our first study, we asked the operators whether these tests were going on and being considered and we were told that, particulary BP that a test like this was being planned and so, I can't tell you more than that. I don't know whether it was executed

or not but certainly as of two years ago there was -- we had definite information and it's recorded in our report to you.

BY: MR. PARR

Well is there anything gained by holding off on injectivity tests?

BY: DR. DOSCHER

Oh, I would -- I couldn't see that at all.

BY: MR. PARR

In other words, the most prudent course might be, in a field like this, to have gone in with injectivity tests very early in the game.

BY: DR. DOSCHER

Yea, well, I think there was made, I think there was some made. I can't tell you all of it because I'm not privy to it, but I believe there were some tests made and yesterday you heard that a test had been made in the aquifer and in the oil column in the tar sand. So, injectivity tests have been made..ah..maybe not as early as I would have suggested, but they have been made and apparently available for the Board's consideration.

BY: MR. PARR

Thank you.

BY: MR. MILES

Are there other questions for Dr. Doscher? Doctor, thank you

very much. If there's no more questions -- I hope you'll hang around as long as you can.

BY: DR. DOSCHER

I'll be here. Okay.

BY: MR. MILES

We'll take a brief five minute recess and come right back and continue with the hearing.

OFF RECORD

ON RECORD

BY: MR. MILES

We have..ah..we have a number of representatives of the industry..ah..who will be testifying next, prior to that just a brief statement to let folks know the status of the world on the second floor right now. The status is Joe, what would you say, limbo

BY: MR. HAYES

Limbo.

BY: MR. MILES

We may -- we may be called away, we may not, nobody really knows right now, if we are we'll just have to vacate..ah.. if that's the case, we do go adjourn, it's my plan that we come back and finish the..ah..finish taking the testimony from the witnesses and I would hope that the committee would join me back here even though the post adjournment celebrations are always in order. At least through the

witnesses that are out of town witnesses who have been kind enough to come and join us. If we don't adjourn, it's my intention to..ah..probably break at 5:00 and come back at 7:00 and hopefully we can..ah..hear from a couple of other people who have indicated they would like to make a statement, ..ah..following that just a general question and answer period, it seems like there's a number of questions that have arisen that people aren't real clear on and maybe give and take between the witnesses might help, if the witnesses can stay. If they can't, I'd certainly understand, I wouldn't want to ..ah.. have anybody miss their plane, but this has really been valuable set of hearings for me. I can't speak for anybody else and I really appreciate everybody's help. Without fur 220 adieu then.ah.. Paul do you want to start introduce your people and their various fields of expertise and go ahead with your presentation in the manner that you choose.

BY: MR. NORGAARD

I'll do that, if I may, I'll introduce them as I go into what I have prepared before, if that's alright.

BY: MR. MILES

Okay, can you tell us who we're talking to though first, to start out with?

BY: MR. NORGAARD

Well, definitely, sure I will. Larry Smedley with Exxon, he'll be talking principly about the reservoir and you're? Allen Lasky?

BY: MR. NORGAARD

That shows how well I'm prepared.

Brian Davies of Sohio, he's going to be talking about reservoir preformance, Dave Griffiths with ARCO, will be talking about the waterflood plans.

BY: MR. MILES

Okay, go ahead Paul.

BY: MR. NORGAARD

Thank you Mr. Chairman. Committee members, I join the Prudhoe Bay Unit Owners in thanking you for the opportunity to discuss the Prudhoe Bay reservoir here this afternoon. I am Paul Norgaard, I'm Vice President with ARCO Oil and Gas Company, a division of Atlantic Richfield Company. I'm responsible for ARCO's activities north of Fairbanks, which includes the Prudhoe Bay Unit. This afternoon I'm here as a management representative for the major owner companies. I believe our prepared testimony, our direct testimony, will be responsive to many of the quetions which I have heard you ask today of the other witnesses. To begin, I would like to summarize some of the activities in which the major owner companies have been engaged since field discovery. As you are aware, the Prudhoe Bay State No. 1, Sag River State, and the Put River No. 1 wells were completed in 1968. Information from these wells, plus seismic data, was

immediately used, and used as input into our mathematical reservoir simulators, and we began our first reservoir simulation studies.

(Discussion regarding blinds)

Obviously this initial data was incomplete and the results of the studies were simply used as a guide to facility design and to overall general reservoir management. The owner companies initiated a very aggressive data gathering program with the start of development drilling 1969. We obtained basic data from cores, that was mentioned yesterday, these are underground rock samples that are recovered in most incidences from 8500 to 9000 feet deep, brought to the surface and analyzed there, from the fluid samples, many of these samples were collected right at reservoir conditions, right at 9000 feet, and finally from the numerous logs which were run (indisc) and all the wells drilled today. In addition, we developed highly sophisticated laboratory tests and interpretive procedures to analyze these tests. Some of them essentially brand new to the industry. The owner companies began immediately to share the bulk of this data to assure the best possible reservoir studies and therefore reservoir management. In addition, the owner companies agreed on the location and sizing of facilities to minimize a surface damage or change to the Prudhoe Bay area. The major interest owners met on several occasions to exchange

and discuss these reservoir studies, the facility studies, and on several occasions met with with the Oil and Gas Conservation Committee and with some legislative committees to share our understanding and our knowledge. I should mention that we continually changed and improved the mathematical reservoir simulators to better reflect the real reservoir, something we always look forward to. As development wells were drilled, the frequency and location of shale was better -- became better known and the rock characteristics, fluid characteristics were better refined. The major owners, in general, were making improvements and in refinements in their reservoir description and in their simulators at least once every year. Prior to the May, 1977 unitization hearings, the three major interest owners finalized a series of extensive simulation studies to address the major reservoir management uncertainties and questions. These were offtake rates, gas sales, water injection, and the timing of additional facilities. These results were summarized at the May, 1977 Pool Rules Hearing and are a matter of public record. It should be noted that this operating plan provides for and contains several key elements and I'd like to mention several of them here for the record.

BY: MR. MILES

Paul, were there -- you said they were summarized in public

record. Were those runs similar to the ones we have in (indisc - cough)

BY: MR. NORGAARD

Most of the runs that were made prior to the unitization hearings were two dimensional strip models which all three companies participated in running and the results from all three companies were incorporated in the hearings and..ah.. presented in the May, '77 hearing.

BY: MR. MILES

Let me start over. Were those runs similar to the ones vanPoollen did in '77, '76 and '77?

BY: MR. NORGAARD

They have the basic perameters, we like to believe that we had a little better tool to use because we had more time to develop it.

BY: MR. MILES

I see, now, those runs are a matter of public record.

BY: MR. NORGAARD

Ah..the results of the runs are a matter of public record. We have not kept them from anyone intentionally, it's just that with simulation work you get an awful lot of output as I believe, Mr. vanPoollen showed yesterday and it -- most -- most times it doesn't warrant getting into if the results look they're consistent and compatible.

BY: MR. MILES

I see, but what Mr. vanPoollen provided us are a number of ten

test runs with..ah..aquifer and no gas sales, 1.5, two billion cubic feet, are those how yours are broken down?

BY: MR. NORGAARD

In general, yes.

BY: MR. MILES

Okay, and is that information available to us as public record in a form?

BY: MR. NORGAARD

Yes it is. Certainly, it's in the testimony itself.

BY: MR. MILES

Oh great. Okay, fine. I haven't got a copy of that, I'd like to see that if you could send it to us.

BY: MR. NORGAARD

I'm sure we can make sure it gets to you, yes.

BY: MR. MILES

Thank you.

BY: MR. NORGAARD

Moving back to the key elements of the Pool Rules. First, an oil production rate of 1.5 million barrels per day which we've heard repeatedly during -- up to this point in time. Second, gas pipeline deliveries of 2 billion standard cubic feet per day when treating and transportation facilities are available. The drilling of wells on 160 acre spacing or denser if necessary. Four, installation of low pressure gathering system and artificial lift when necessary to maintain the

AGO 532333

production rate. Fifth, selective injection of produced water into the producing horizons, sadlerochit formations, in areas of low natural depletion when water volumes are significant, and last, supplemental injection of source water when optimum injection locations and volumes can be determined, additional recovery predictions verified, and the project's economic viability can be confirmed. One key point made at the hearing and later by the Oil and Gas Conservation Committee was the need for production history to verify the study results and provide a basis to calibrate the reservoir simulation, the simulators themselves. We are now two years into production history and possess some of the needed history. During this two year period, extensive data has been obtained and has been continually analyzed. We have provided summary reports, as well as the basic data itself, to the Oil and Gas Conservation Commission. The owner companies have developed three-dimensional fieldwide models to fully utilize this data and have conducted studies to again analyze, refine and improve the quality of our reservoir management plan. This careful analysis demonstrates that the field is performing very well, at least as well as predicted, and slightly better in some regards. Nevertheless, we must continue to gather and analyze additional data to fully optimize this field. The studies for a source water injection system have moved forward in parallel with the

reservoir studies. The pace and detail of these studies has increased during the past two years with good progress in all study areas. Last week, the permit application was filed with the Army Corps of Engineers. We shall discuss these items in considerable detail later in our presentations. Moving now to our presentation. All three major owner companies have participated in the studies which we shall be discussing and in the preparation of this hearing. We have broken our discussion into three parts. First, Field Performance, and as I indicated this will be presented by Brian Davies of Sohio. Second, Reservoir Management Studies, this will be presented by Larry Smedley of Exxon. And last, Waterflood Study Progress which will be presented by David Griffiths of ARCO. Since the pieces of our presentation are inter-related, we suggest that clarification questions be asked as they arise, but that new type questions, leading questions be held until later since in a high probability much of your questions will be answered as we move forward in our testimony. Certainly, we encourage your questions, we want to answer all of your questions, but we think we can more efficiently answer them if we go through our prepared testimony. But, without a doubt, any clarification questions, please ask them immediately because that's the right time.

BY: MR. MILES

Nobody asks leading questions on our committee except Chat.

BY: MR. NORGAARD

Last, copies of the text will be made available at the conclusion of our presentation. And with that, I'll turn it over to Brian Davies who will be talking about the Field Performance as we see it. Brian.

BY: MR. DAVIES

Mr. Chairman, Members of the House Resources Committee, Ladies and Gentlemen; my name is Brian Davies. I hold a Honors Degree in Natural Sciences from Trinity College, Dublin. I have been employed by British Petroleum and Sohio in petroleum production and exploration activities for 16 years in the North Sea, Arabian Gulf, Columbia and Alaska. Since 1971, I have been involved in the development of the Prudhoe Bay Field, first, as District Petroleum Engineer then as Sohio's representative to the Prudhoe Bay Unit Planning Subcommittee in Anchorage. My current position is Supervisor of Production Planning for Sohio and as such I continue to be involved with the development plans for the Prudhoe Bay Field. The purpose of my presentation to you today is to describe production performance of the Prudhoe Bay Field today. I will start with a summary of the field development since the commencement of production in June of 1977. Next I will briefly discuss the reservoir surveillance methods that the operators are using to monitor the field performance.

I will then discuss the production and pressure behavior, the well performance, and the fluid contact movements in the reservoir. I'd like to say right now that overall the production performance has been good and essentially as predicted. The Prudhoe Bay Field has been on sustained production for just over two years. I apologize for the switching on and off but we'll get through that here. Ah..initial offtake from the field was restricted to about 720 thousand barrels per day, because of the accident at Alyeska Pump Station #8. After the repairs to the Pump Station were completed in March of 1978, the rate of production was increased to about 1.16 million barrels per day. Since then, the performance of the pipeline system has been progressively improved so that currently an offtake level of about 1.28 million barrels per day is being achieved. In the field, we have maintained sufficient producing potential so as to continuously produce at pipeline capacity rates. Early production from the field was sustained by approximately 100 wells in total serving two flow stations in the Eastern Operating Area and two Gathering Centers in the Western Operating Area. By the end of the first three months of production, all facilities were functioning satisfactorily. And also, the flaring of gas ceased except during the commissioning of new facilites and for emergencies caused by minor upsets in the operation of the plant. Of the total of

500 billion standard cubic feet of gas produced since January 1, 1978, over 99.8% has been reinjected into the reservoir or used as fuel. Because, we emphasize that, 99.8 has been reinjected into the reservoir or used as fuel.

BY: MR. MILES

Which -- which percentage of -- which has been..ah.. what percentage has been reinjected, with what percentage has been used for fuel?

BY: MR. DAVIES

Approximately as Dr. vanPoollen and the OGCC mentioned, over 90% has been reinjected into the reservoir.

BY: MR. MILES

So, roughly 9.8's used as fuel.

BY: MR. DAVIES

Yes, roughly. I don't have the breakdown on that, we can get that for you, if you wish. Continuing on with the history of development to date..ah..the third Gathering Center in the Western Operating Area was commissioned in March of 1978, and the third Flow Station in the East came on stream in March of this year. These facilities have enabled additional wells to be progressively brought on production and so have permitted offtakes to be distributed more evenly over the field. We currently have nearly 200 wells drilled and connected for production. Thus, over a period of two years this represents a doubling of the number of wells available for production. And we are proceeding with the further

development and the operation of the Prudhoe Bay Field in a manner which is consistent with the plans presented in the May 1977 Pool Rules Hearing before the Oil and Gas Conservation Committee. These plans permit the degree of flexibility that is necessary for good reservoir and production management control. Turning now to the question of reservoir surveillance. In the previous testimony to the Oil and Gas Conservation Committee in May 1977 the Unit owner companies described their plans for reservoir surveillance. The owners recognized that a comprehensive reservoir surveillance program was necessary to provide the data needed to optimize the continued development of the field. The response of the reservoir to production is indispensable in understanding the recovery mechanisms and in checking the accuracy of reservoir descriptions. In addition to frequent well testing the owners proposed an intensive reservoir pressure measurement effort, a program designed to monitor changes in gas saturation and an evaluation of techniques to monitor changes in the water saturation of the reservoir. Subsequently, the Alaska Oil and Gas Conservation Committee issued Conservation Order No. 145 which incorporates rigorous surveillance requirements in the Prudhoe Bay Oil Rules. Over the last two years this surveillance program has generated a tremendous volume of field performance data. In our view the level of reservoir surveillance and testing activity which

has been carried out and which is continuing in the Prudhoe Bay Field has rarely been surpassed. This viewgraph summarizes this surveillance activity. We have over 450 measurements of reservoir pressure and 220 flow meter surveys have been run. These flow meter surveys are used to establish the contribution of the various intervals that are open to production in the well bore. In addition to this, 215 initial baseline and follow-up surveys have been done to monitor the changes in gas saturation in the reservoir. The neutron logging tools which are used in these surveys have proved to be extremely valuable in locating the leading edge of the advancing gas cap and also in monitoring other changes in gas saturation around the well bore. Some 60 surveys have been made to attempt to monitor the changes in the water/oil contact in the reservoir. As was pointed out in the May 1977 hearing this is a difficult technical problem. However, the aggressive evaluation program has given us encouraging indications that a technique is available which will yield quantitative estimates of the changes in water saturation caused by any rise in the water/oil contact.

BY: MR. MILES

Can you give me just a short idea what you do when you do one of these surveys -- what -- what actually happens?

BY: MR. DAVIES

Ah..well, depends on which..ah..one your dealing with. Lets

for instances look at the gas/oil contact survey. There is a..ah..tool we use, is called a neutron tool and basically, that bombards --you lower the tool down the well bore and the tool bombards the formation of the neutrons and the response of the tool..ah..is dependent among other things, upon the gas saturation that's present in the reservoir at that point. What we do is we run the tool initially to establish a base-line survey and then after some period of production..ah.. we'll shut the well in and run the tool again and look for changes from our initial baseline survey. By doing this we have found that -- we have a very good technique for detecting these changes.

BY: MR. MILES

Thank you.

BY: MR. DAVIES

Let me now briefly review the production history since June of 1977. This viewgraph shows the buildup in oil production from an initial rate of 720 thousand barrels a day to the level of 1.28 million barrels per day in June 1979. Also shown is the production of gas which is associated with the oil, that's the..ah..red line. As I'm sure you're aware, the ratio of the produced amount of gas to oil at any particular time is referred to as the gas/oil ratio, a term that we've heard a lot about today. At the start of production this gas/oil ratio was approximately 750 standard cubic feet of gas per

barrel of oil. The ratio has risen somewhat and currently in July of 1979 is approximately 920 standard cubic feet of gas per barrel. This slight increase in the overall gas/oil ratio is primarily due to wells in the Eastern part of the field, particulary in the Flow Station 2 area, that's in the extreme Eastern part of the field. This increase is mainly caused by the localized influx of gas cap gas under the continuous shales in this area. Currently the operators have considerable flexibility in controlling the gas/oil and the oil/water ratios, and they are deliberately producing high gas/oil ratio wells which are locate high on the structure and close to the gas cap so that they maximize the recovery of the gas condensate liquids, while excess gas injection capacity is available. Before we leave this viewgraph, I'd like to point out the line, right at the bottom, it's barely distinguishable from the lower-most axis of the graph, represents the water production which has been very low and currently amounts to just under 20,000 barrels per day. The data that's obtained from the reservoir pressure measurement program is, among other analyses, used to draw maps of the pressure decline at various times. This particular viewgraph shows such a map which corresponds to our interpretation of the decline at August 1, 1978. Can anyone -- everyone see that? Each line...

BY: MR. MILES

....probably doesn't make a hell of a lot of difference.

BY: MR. DAVIES

Your -- you just can't see the detail or....

BY: MR. MILES

No, I can.

BY: MR. DAVIES

This particular viewgraph, as I've mentioned, shows the interpretation of the decline to August 1, 1978. Each of these lines connects a point at which we believe the reservoir pressure is the same. This line, here for instance, is the contour line corresponding to the 100 pounds per square inch decline level. You will note that the area showing the greatest decline occurs in the Flow Station 2 region. This line here represents a decline of 600 psi, at that time. Once again, this is caused by the unusually high incidence of shales which prevent good vertical communication of the producing intervals with the overlying gas cap. And, as I mentioned before, these shales are also the cause of the localized influx of the gas cap gas. We will discuss this matter in some more detail later, and show that the performance as was predicted. We'd also like to emphasize that this is a relatively small part of the field and that the intervals affected contain less than 6% of the oil in place in the reservoir. To avoid any further increase in the pressure decline in this area, we changed our production offtake distribution and reduced the amount of oil that was

being withdrawn from the Flow Station 2 area. This next map shows the reservoir pressure decline corresponding to August 1, 1979. Due to the reduced production from the Flow Station 2 area, the pressure sink, that's this area here, that pressure sink has stabilized and is now no greater than it was one year ago. You see that this line here is corresponding to 600 pounds of decline, and as I say, that was the decline that we'd saw there one year ago. In fact, in some of the wells, in this area, there has been an increase in the reservoir pressure during the past year. Another factor that I should point out, and this is one that has been referred to in testimony by..ah.. the OGCC and by Dr. vanPoollen, is that the pressure measurements, that we take, reflect primarily the pressures in the reservoir intervals that are being drained. Where the presence of extensive shales impairs communication with other parts of the oil column, then the measured reservoir pressure will be lower than the average pressure of the total oil column in the reservoir at that location. When we take into account the distribution of the pressure, both in an aerial sense, looking across the whole field, and also in the vertical sense taking into account the intervals that are not open to production, then the pressure decline for the oil column is approximately 185 psi, pounds per square inch. And this is actually less than was predicted prior to production

and is certainly no cause for alarm. Let me turn now to the question of well performance. The well capacities average about eleven and one-half thousand barrels per day and these two are in good agreement with our preproduction predictions. It has been suggested that gas coning is causing production problems at Prudhoe Bay. It is a fact that in wells, where there is relatively good communication between -- in the vertical section between the producing interval and the overlying gas cap, there is a potential that early gas production will occur.

BY: MR. MILES

Before we go off that, Brian, did you say that in some areas the pressure's higher?

Brian, did you say that in some areas in Prudhoe that the pressure was higher than originally?

BY: MR. DAVIES

No, what I said was, turn back, in a pressure sink area, perhaps we could put the thing back in here, in this pressure sink area one year ago we recognized a significant decline right in the core of the sink, so we reduced the production off-take from that area. Ah..... Well, we look at the map one year later, we see that the pressure -- sink has not increased, there is no decline greater than 600 pounds. In some wells in that area, we are actually

seeing an increase that are a bounce back. Let me put it to you -- there are many...

BY: MR. MILES

....so it's not bouncing back over the original pressure, it's bouncing back from the drop of 600?

BY: MR. DAVIES:

Let's say a year ago we might have measured, for example, 550 pounds decline in a particular well and this year we'll be measuring..ah..for example, 450.

BY: MR. MILES

Did you indicate what percentage of the field -- these are -- that's a substantial drop, is that right? 600 pounds pressure?

BY: MR. DAVIES

That -- that is a substantial drop compared with the rest of the field where we're looking at..ah..well, in that first map, in the order of 200 pounds.

BY: MR. MILES

Okay, did you say here a percentage of the field that the substantial drop was measured in?

BY: MR. DAVIES

Yes, I....

BY: MR. MILES

....you say it's 6% or....

BY: MR. DAVIES

We have to take into account both the aerial effect again,

AGO 532346

and the vertical effect. What I said was that, if we look at the intervals where we measure that pressure, and bear in your mind that these intervals are isolated by shale, then the amount of oil that's effected is 6% of the oil in place. What I'm getting to is that it's not just a matter of the aerial extender which is pressure sink, we also have to look at the limitations in the vertical section, and when we do that, then the amount of oil that we're looking at that is seeing this larger than average, very much larger than average, pressure drop is only 6% of the oil in place.

BY: MR. MILES

What does that mean for downstream recovery?

BY: MR. DAVIES

What -- I'm sorry I don't quite see the.....

BY: MR. MILES

Well, okay, it's a 6% drop in this isolated area...

BY: MR. DAVIES

....no, it's no 6% drop....

BY: MR. MILES

Well it basic -- okay, it's -- yes, 6% of the oil in place. Is that right?

BY: MR. DAVIES

The oil affected by this large decline is 6% of the oil in place.

BY: MR. MILES

6% of the oil in place, in other words, what you're saying is

that the greater part of the oil is not affected by this very large initial decline. Okay, what does that -- what does that very large initial decline -- how does that affect future recovery?

BY: MR. NORGAARD

Mr. Chairman, we will be addressing that directly in testimony, a little later, if that's alright. We can answer it now if you like.

BY: MR. SMEDLEY

Ah..this performance, as you'll see later, was predicted almost identically in the projections that -- that we've used to get the recovery figures that we're citing. So, in effect, it doesn't have any. In other words, it was considered, I'll show some comparisons with this same chart ..ah..from the predicted runs.

BY: MR. MILES

Mr. Chatterton.

BY: MR. CHATTERTON

I am on the point of clarification -- if your going to touch on this and that, why just say so, and go. Obviously, I'm looking at iso -- pressure lines there, is that correct?

BY: MR. DAVIES

That's right.

BY: MR. CHATTERTON

Okay, and I didn't see the previous slide fast enough to see

how much variance there was over the years time. You might put that up. Okay, fine, Now, let's get back to the other one. And, my question now is basically -- and you, sir, you may be answering it later on, but basically, where the intersection of the truncation line is at the top of the zone and -- and at the base of the zone in that -- on that plat there. You're out in an area where you don't have a full sand thickness, aren't you?

BY: MR. DAVIES

Yes...

BY: MR. CHATTERTON

Right, now, are you also within an area where you have gas cap overlying you completely or does the oil zone go to the top of your zone?

BY: MR. SMEDLEY

In much of the area there's no gas cap over (indisc)

BY: MR. CHATTERTON

No, gas cap over it. So it has -- yea -- okay, thanks.

BY: MR. MILES

Mr. McKinnon.

BY: MR. McKINNON

Yea, you said that when you look at it aerially, it -- it may be a large portion of the field, but when you look at it vertically, it doesn't affect -- it only affects 6% of the -- And that's because you're drilling between shale layers and the

pressure loss is confined between those shale layers.

BY: MR. DAVIES

We drill all the way through -- that..ah..if you recall the diagram that..ah..Mr. Hamilton showed you where having drilled the case to well, then you lower a perforator down and zap holes into the (indisc. - simultaneous speech) We just zapped holes in that particular area between the shales.

BY: MR. McKINNON

Okay, and what you're saying, it doesn't effect the area above it or below it.

BY: MR. DAVIES

Because the shales there are quite extensive and there's not ..ah..good workable communication between the producing interval of the -- interval above the shales, then the pressure drop in the interval, direction of measuring in.. ah..is not representative of the whole oil column.

BY: MR. McKINNON

Will that help when you go up to the next interval or down to the next interval?

BY: MR. DAVIES

When you -- when you open -- if and when you open up the intervals that are not bounded by the shales, then you'll see the pressure response from those particular parts of the reservoir. You'll see a high pressure.

BY: MR. McKINNON

Let me see if I can get -- if the whole interval were open, you would not see that pressure drop.....

BY: MR. DAVIES

That's right.

BY: MR. McKINNON

.....because the well would break and record something that approaches very close the highest pressure that it sees or at least a composite of the two. So, if the whole interval were open, that 600 pound pressure sink might look like 200 pounds and that's what Brian's dealing with when he says you have to look at both the horizontal and the vertical -- make a -- I guess it's just a straight calculation on what is effected.

BY: MR. SMEDLEY

We confirmed this with some tests that we..ah..that those zones above those shales are -- you know -- substantially higher pressures or near original pressures and have not drawn down nearly anything like this.

BY: MR. NORGAARD

Also, it may not be germane but we have taken this area and looked at it in a very microscopic context with simulator models, rather than with the larger models, we have taken a look at it in a very fine context and have been able to match exactly what's happening in the real world with what we

suspect would happen with a simulator, so we can tell very closely what in fact has happened. We've been able to history match. That's the kind of thing we will do and we have done anytime we see an anamaly, we get the best technical expertise we've got available and take a look at it.

BY: MR. McKINNON

Has this situation shut down some wells?

BY: MR. SMEDLEY

That was the method of reducing the production -- Brian mentioned that we reduced the production rather than cutting the production back at all the wells, we did shut some of the wells in that were right in that..ah..area, in the highest pressure drawdown area there. Drill size 9 wells, particularly.

BY: MR. McKINNON

Did..ah..

BY: MR. MILES

Joe, are you done or.....

BY: MR. McKINNON

Yeah....

BY: MR. DAVIES

We were about to get on to coning. As I've mentioned, we've heard quite a bit of discussion on coning and..ah..we'd like to run through this diagram here to just explain what happens. This is a phenomena which occurs -- occurs in the well where there is relatively good communication in the

vertical interval between the producing interval down at the bottom and the overlying gas cap. As oil is produced from the perforated interval of the well, pressure drop is felt at the gas/oil contact so we're producing from these perforated intervals here and we feel a pressure drop opposite the original gas/oil contact. This pressure drop..ah..can result in the contact being locally drawn down around the well bore, and here we see the contact is dipping down around the well bore.

BY: MR. MILES

So, the gas is actually sinking?

BY: MR. DAVIES

Yes, the -- what's happening here is that the -- when field pressure drops here..ah..pressure drop due to production here is felt up here and that closes the gas/oil contact so it tilts into -- towards the well bore.

BY: MR. MILES

So the -- physically, the oil drops down -- the well bores between my fingers -- the oil drops down and that -- that area is -- the gas cap moves down into that area?

BY: MR. DAVIES

Right. It's sucked in. Like the -- I think the analogy that someone made when you stick a straw in a milkshake, a rather viscous milkshake, and you suck hard on it and you get this sort of coning down around the well, that's exactly

what happens when you drill the wells.

BY: MR. CHATTERTON

Brian, clarification question. If the mobility, relative permeability, was equal for the oil and the gas, would you expect to see that?

BY: MR. MILES

Can I pass that one?

BY: MR. DAVIES

Paul can answer it.

BY: MR. SMEDLEY

I'll try that one. The..ah..the mobility, the gas being much more mobile, contributes to this problem, the density difference between oil and gas combats this phenomena, in other words, the density difference is trying to keep that contact very sharp so you've got kind of opposing forces -- that you really try to balance. (indisc.)

BY: MR. CHATTERTON

Thank you.

BY: MR. DAVIES

Okay, so, as one produces, through the perforations, the oil - gas/oil contact starts the coning down until eventually gas is produced through the uppermost part of the perforated interval. This is the fully developed gas core and when -- when you refer to a well coning gas, that's what's happening, you develop the cone so gas is being produced

through the uppermost parts of the perforated interval because the cone is developed all the way down to the top of the producing i. erval. Now, as we discussed at the May 1977 hearing, we deliberately restricted the interval of the reservoir that is open to production in some -- such wells. Perhaps we can take this (indisc.) By that I mean that we have chosen not to perforate up here, we have restricted our perforations to the lower part of the interval. We have generally maintained a distance of 200 to 260 feet between the top of the interval and the gas cap and this is in order to minimize the potential for this coning effect. In general, the further you stay away from the gas cap, the less the potential from coning gas.

BY: MR. MILES

What happens if something is -- you screw up and you suck some of that gas cap into the bore.....

BY: MR. DAVIES

What's that?

BY: MR. MILES

.....you suck some of the gas cap up into the oil or does technology prohibit that if your gas cone come to the top holes where you're drawing the oil out, what happens?

BY: MR. DAVIES

When the gas coning comes down to top holes, then you stop producing gas cap gas.....

AGO 532355

BY: MR. MILES

It just goes right up in the top.

BY: MR. NORGAARD

.....and you just produce the higher amount of gas. That's it. The (indisc.) gets reinjected back into the gas cap. That's what happens and that's the most serious thing that can happen to you.

BY: MR. MILES

Thank you.

BY: MR. SMEDLEY

The question was asked here yesterday and I don't think it was fully explained. It is a reversible process and -- you know -- it's not a real serious problem. It's something tha when it happens, you can reverse it.

BY: MR. DAVIES

As I mentioned, we have, generally, maintained a -- this standoff distance of 200 to 260 feet and we found that this policy has been very successful in preventing gas coning in the highly productive wells completed under the gas cap. In short, we can say that gas coning has not been a significant problem at Prudhoe Bay. One side effect of this practice is that it reduces the production capacity of such wells and thereby increases the number of wells that are required to make a given production rate from the field. We also have similar restrictions placed upon how close to the oil/water conta

we open up for production. And, so by adopting these measures, we are surrendering the short term benefits in the well productivity in exchange for the longer term benefits that will be derived from the more efficient displacement of oil by overlying gas and the underlying water. It's a long sentence but let's punch it home. In essence, we have spent more money, drilling more wells early, in order to ensure better long term reservoir performance.

BY: MR. PARR

May I ask a question, if you compensate for this by drilling more wells, don't you get the same end result?

BY: MR. DAVIES

No.

BY: MR. PARR

You're spending more money to do it, I understand, but in terms of what's coming out of the reservoir, you drill more wells you're getting the same result.

BY: MR. DAVIES

Well, the answer to that, I think, is that gas coning is..ah.. principally a function of the rate from a well and this business of how far you keep away from the gas cap. So, it's -- if you draw a high rate from the well, then you'll have more potential for gas coning. If, however, you increase the number of wells and limit your perforation intervals, you will not have gas coning.

BY: MR. PARR

Well, maybe I don't quite understand you but if I understood your statement. Ah..because you use this 200 and 260 feet distance, you reduce the production and that you compensate for this by drilling more wells. Now..ah..so what is that doing in terms of benefits to the reservoir which is what I understood. It appears to me you're pulling the same amount of oil out of that reservoir in either case, right? If you have ten wells pulling out 10,000, that's 100,000, one well putting out 100,000 that's 100,000. So, I mean -- what's -- I don't understand how you're gaining anything here in terms of protecting the reservoir.

BY: MR. DAVIES

Well (indisc.) -- maybe the slide will help. First, as we developed this cone down here, we started getting a gas producing in the bottom and we're not allowing -- we are allowing, I'm sorry, basically, we are accelerating the time in which we see gas entering the well, and so, in this particular area, we are..ah..we're not efficiently, as efficiently..ah..displacing the oil by the gas as if we restrict the production rate. We keep that gas cone high.

BY: MR. NORGAARD

Let -- let me take a shot at it, if I may. The ideal, the textbook case that I think people are talking about would be if this gas/oil contact moved uniformly all the way across th

reservoir straight down. That's -- that's the textbook case. There are some reservoirs in Canada, as a matter of fact, where -- that are very steep where -- where they really are bringing it down, straight down, and by having more straws than you avoid the little bumps, the little anomalies and that again by textbook case, should be beneficial. I don't think that there is any way that that can be verified or substantiated but in textbook case, it would be desirable to do. Does that help?

BY: MR. SMEDLEY

If you elected to do what I think you're suggesting, why don't you just go ahead and perforate the whole thing, but have more wells, that's what (indisc. - simultaneous speech)

BY: MR. PARR

I didn't suggest that, this gentleman said you drilled more wells to compensate for that lower production or.....

BY: MR. SMEDLEY

.....lower capacity.

BY: MR. PARR

Well, alright, lower capacity. The point is -- you know -- how is this protecting the reservoir by drilling more wells and if your getting the same amount of production.....

BY: MR. SMEDLEY

That's a long term thing. As you look -- you know -- as this reservoir's producted, what's going to happen is that that gas/c

contact, as original, it is going to advance, in fact, it is already moving and we are already monitoring its movement. It will move down, down towards those perforations. If we weren't prudently perforating the wells with the standoff li we are, if you perforated, for instance, up close to where that red line is, as that contact advanced, even without coning, the gas would come right into the well bore and you'd be faced with a mechanical repair which is difficult.. ah..not as risky, a lot of time we lose wells when you try to do this..ah..and very expensive. So it's -- that's a part of the reservoir management that you're optimizing. To me there's another point that really hadn't come across strong enough to this, in regards to -- we've talked a lot in the last few days about coning. To our knowledge, there has not been a well at Prudhoe Bay yet that has exhibited this behavior. We have not coned gas into a well at all in Prudhoe Bay. So, we've talked a lot about something that is actually -- there is a potential there, as Brian indicated, we've always anticipated, we've indicated that in the long term we will see this type of behavior up there, but as of now, we have not and it has been because we have perforated the wells in this manner.

BY: MR. PARR

Thank you.

BY: MR. NORGAARD

I hope we answered it close enough.

BY: MR. CHATTERTON

Could I intercede as a friend of the court, so to speak, and try to talk to Charlie to get a feel for this? If your seat cushion had 4 vertical spikes on it, it would hurt like hell to sit on it, right? If you put 400 vertical spikes on it, it would not hurt very much. And it's the same analogy as this. (laughter)

BY: MR. PARR

Perhaps I misunderstood Mr. Davies, but I understood him to be saying or at least implying that this was a conservation technique which would result in better management of the reservoir. I'm not interested in whether it's a good test -- economically for the companies or any of those factors. The additional cost benefit ratio for several wells as opposed to one. I understood him to say that this was a technique which was better management of the reservoir and I was thinking in terms of not wasting oil or getting maximum recovery and so forth and therefore I didn't understand how this made any difference. Now if I did misunderstand something, then of course, I've wasted your time.

BY: MR. SMEDLEY

I think in the context it is -- it's an improvement in reservoir management -- to quantify it would be really impossible. I think it's a textbook thing like we've talked about a number of times before. Directionally, it's got to

be good. You know, how much good is it, I don't think anybody could ever answer that. It's just one of the variables.

BY: MR. PARR

Thank you.

BY: MR. SMEDLEY

To get the maximum recovery of oil though, that's what we're after. In this type of mechanism where the gas/oil contact is advancing, you will ultimately need your performations as low as you can in the reservoir. That's how you maximize recovery.

BY: MR. ROGERS

So, if I understand it right, coning would decrease recovery because your pressure would drop faster.

BY: MR. NORGAARD

Not really, because all the gas that you take out goes back into the gas cap so really it has no impact at all on pressure other than the fuel that you would consume to compress the gas to put it back in the ground.

BY: MR. ROGERS

So there would be some loss and is the reason -- do you think the reason that you had no coning is because you've got more wells producing?

BY: MR. SMEDLEY

It's because we perforated the wells like this. By perforating the wells like this, we ended up with less initial producing

capacity than had we perforated the pipe all the way. That in turn resulted in more wells. So it's really a combination. The well rates are lower per well because of the perforated policy and also coning has less of a tendency because you've increased the distance from the perforations to the contact - so both facts.

BY: MR. ROGERS

And whose decision was it to have more wells, was that the producers or the commission?

BY: MR. SMEDLEY

That was our decision but it was a program prior to production startup was discussed with the Oil and Gas Conservation Commission and they endorsed it.

BY: MR. NORGAARD

I think both really had a role to play in that decision.

BY: MR. ROGERS

How about the eastern wells, ARCO, ones that were shut down, was that your decision or ....

BY: MR. NORGAARD

Yes.

BY: MR. CHATTERTON

Well, before they leave I've got a couple of general questions here, Brian if I may. One, is -- you followed the display of the rather sensational pressure sink and it was very sensational because we didn't have a third dimension to the

drawing and you explained that, but you followed it immediately with coning -- and so, that did not result from coning because you didn't even have any free gas over that area because of the (indisc.--cough), is that correct?

BY: MR. DAVIES

Ah.. that did not result in coning because in that particular

area we have shales between the perforated intervals and the gas cap, and so in that situation you don't see coning as a result of the shale blocks -- you put a shale in here then the original gas cap does not see the pressure drop caused by production through the perforations. Thus, the cone does not form.

BY: MR. MILES

The cone doesn't -- doesn't perforate or doesn't go through a shale.

BY: MR. DAVIES

No, because the shale blocks the transmission of that pressure drop up to the gas cap.

BY: MR. McKINNON

What is the phenomena then that results in the lowering of pressure and all the gas come in the ....

BY: MR. DAVIES

What the phenomena there is that, we should have a diagram, basically, we have -- let's say the gas/oil contact is here, like this, and you have a well producing down here and as the pressure comes down, the gas tends to underride the shale and come down underneath its (indisc.).

BY: MR. SMEDLEY

Maybe even more simply, if we -- and we have done this on some wells, had an impermeable shale here and impermeable shale here and chose to perforate in between, which we

frequently did, particularly in the Eastern area, not knowing whether this shale would be continuous or not, because you have to watch the pressure area and gas/oil ratio behavior really to decide. Since we perforated right between two continuous shales there's no way that the -- that you can get gas cap pressure support or pressure support from the rest of the oil column, or in your aquifer, if you have anaquifer below, it's isolated. There's no means of pressure support other than just the limited amount of oil that's exposed to the perforation. Then you get rapid pressure drop, and that's what we saw, that's basically the way we are over there in that Eastern area. And we're -- you know -- we're taking steps like where we've proven that the shale is very continuous, it's obvious that we'll have to add a set of perforations on top of it, for instance, to expose it.

BY: MR. DAVIES

Let me answer the question of the..ah.. the movement of the fluid contacts. As I mentioned previously, the neutron tool has been proven to be a highly effective method for monitoring changes in gas saturation in the reservoir. And based upon the results of these surveys, we interpret that the overall movement of the gas/oil contact is of the order of 15-20 feet per year, on average. This is certainly very close to what was predicted prior to production, for the oil offtakes we have maintained to date. We have also

observed gradual rises in water/oil ratios in a number of wells over the last two years. When we match the individual well performance with our reservoir models, the results suggest that the heavy oil-tar zone, which is often present just above the oil/water contact, does not present a barrier to water influx. And, this is consistent with our predictions prior to coming on production. To date the monitoring of the oil/water contact with the logging techniques available has indicated very little overall movement of the contact, which is also in agreement with the previous predictions.

BY: MR. McKINNON

A while earlier somebody had made the comment that it was primarily a gas cap and dissolved, correct? Your saying that there is no problem with the water..ah..is there any water drive involved at all?

BY: MR: DAVIES

Well, its early days..ah.. but, to date, we've not seen very much movement of the oil/water contact (indisc) Which is -- you know -- what we kind of..ah..predicted previously.

BY: MR. McKINNON

Oh, alright, I confused what you were saying.

BY: MR. DAVIES

In summary I would just like to emphasize the following points. A very extensive data gather program has been

undertaken during the first two years of production and this data gathering program is continuing, in order to ensure adequate surveillance of reservoir performance at Prudhoe Bay Field. The data that we generated by this program is largely consistent with our pre-production predictions, and there have been remarkably few surprises to date. In overall terms the field is performing quite well. The next speaker, Mr. Larry Smedley of Exxon will provide some more details of the comparisons between our predicted reservoir behavior and those that we have observed in the field to date.

BY: MR. SMEDLEY

Mr. Chairman, Members of the Committee, my name, as Brian indicated, is Larry Smedley. I have been employed by Exxon Company, U.S.A. since recieving my engineering degree at the University of Missouri at Rolla in 1966. And I have spend most of the past 13 years involved in various aspects of petroleum reservoir engineering. I first became involved in Prudhoe Bay reservoir studies in 1970 and I have spent some six years either studying or supervising others' study of this field. My current position is Division Reservoir Engineer for Exxon's Western Production Division. Each of the major owners of Prudhoe Bay carry out comprehensive reservoir management studies independently on an almost continuous basis. These independent analyses, followed by exchange and comparison of results, provide us added insights

to reservoir behavior. While the study results are not identical, they are similar and have let us to the same general conclusions regarding the proper operating plan for Prudhoe Bay. Now, each company presented their independent studies at the Oil and Gas Conservation Committee hearing in May of 1977 and that testimony is a matter of public record. So, in the interest of time, today I will present only the Exxon study results. I may have a little bit of trouble with these view graphs, this first one, you can see they've put a lot of green backing on these things and they're a little bit dark, but I hope you can follow them. The first figure summarizes the areas that I plan to cover. I will briefly review the reservoir description, highlighting the oil zone rock properties and major shale complexes used in our reservoir model studies. The description of the reservoir is the key to accurate performance predictions, and I will show that the Prudhoe Bay description has not changed much from our pre-production estimates. And next, I will compare the observed pressure and production history to predictions made by our three-dimensional reservoir model. Now, this model was constructed in 1976, prior to production start-up and was mentioned and discussed at the May, '77 Pool Rules Hearing. You'll see that when we review this that performance to date in the field has been encouragingly similar to this early model study result. Finally, I will

review the reservoir study results which then led to the Prudhoe Bay operating plan, I'll highlight various development options that we studied, such as well spacing, artificial lift, waterflooding, and so forth. And, I'll also review sensitivity studies which describe the impact of oil and gas offtakes and the time of water injection on the ultimate oil recovery.

BY: MR. MILES

Larry, I'm going to ask the same question I asked Paul, are those -- are your 3-D models, that you said - from '76, are those public record?

BY: MR. SMEDLEY

The 3-D model was discussed at the Pool Rules Hearing, as you will hear later. The results that we used for the sensitivity studies were based on -- well, it's really what we call a three-dimensional cross-section, it's a cross-sectional type model, it's not what you would think of as a full three-dimensional model of the field, I think I can explain this maybe a little bit better in the context of the total testimony. Those model results and the ones I'll present today are a matter of record, of public record, they were included in our testimony at the May '77 hearing, May, 1977 hearing.

BY: MR. MILES

Are they laid out like the ones from -- vanPoollen is the

only thing we have to compare it by and you guys can dazzle us with terminology, are the same -- you know --....

BY: MR. SMEDLEY

Yes, Mr. Chairman, they are -- we looked at the basic same variations, the same variables..ah..we also presented some results where we varied the reservoir description in areas that you're uncertain as to what the description might be, like shales for instance, and that's one of the things we varied, one of the techniques used in the trade is to analyze the impact with and without those shales. I'll assume it's continuous, I'll assume it's discontinuous -- you know -- what's the impact on the operating plan. So, I think, the major addition that we had to the studies that vanPoollen did is we also did show some results that looked at reservoir property sensitivities.

BY: MR. MILES

Okay, can you send me those?

BY: MR. SMEDLEY

Yes.

BY: MR. MILES

Okay.

BY: MR. SMEDLEY

Okay, this next figure is a well log, and it's going to be equally hard to see I think, but it's got a lot on it that ..ah..we presented it at the hearing, it shows the geologic

zonation of the reservoir, the gamma-ray and sonic log responses that we get from logging through the reservoir, and it shows the location of major, correlatible shale complexes in the Sadlerochit sandstone interval. Also shown, on the right-hand side of the chart, are the average rock properties such as thickness, porosity, horizontal permeability, net sand to gross thickness ratio, and vertical to horizontal permeability ratio. Now I want to emphasize that this same figure, although you could read it a little better then, was presented at the May '77 hearing and is included in the public record of that hearing. And, I've included it here, though it's a rather technical figure, I wanted to include it here really for two reasons. First, the average rock properties, which are shown -- it's hard to read, but for instance the permeability of the various lithologies in the Sadlerochit or the different zones of the Sadlerochit -- you know -- range from about 240 milladarcys in the lower most zone up to in excess of 900 milladarcys , almost a darcy (ph) in the most permeable zone. These are properties -- while I'm not going to try to explain to you exactly what they mean, they are properties that indicate the Sadlerochit reservoir has very good qualities. These are good qualities relative to other reservoirs, they're not the best, but they're good properties. And it is these favorable properties, rock properties that are shown here, in combination

with the thick oil column and a large overlying gas cap that lead to -- the good natural depletion recovery that we are predicting at Prudhoe Bay. The second, and perhaps more important reason that I have included this figure for you here today, is to point out that the description that we provided the Oil and Gas Conservation Commission over two years ago is still valid. We have obtained enormous quantities of additional information, as Brian described, from drilling, logging, coring, and running pressure buildup tests and so forth, since start-up. The new data confirms these pre-production estimates. Now, several newspaper articles have suggested recently that a "shale problem" has been discovered at Prudhoe Bay, and there's been some discussion of that here at this hearing. The major shale complexes that are identified on this log were mapped and included in our reservoir model studies long before the start of production. We provided the Oil and Gas Conservation Commission maps of these shale complexes in 1976. And at that time, we described a technique that we used to evaluate the impact of the many, minor, non-correlatible shales, and you can see on the log the indentations, the small indentations that are similar in direction to the major shale indentation are minor non-correlatible shales that don't go from well to well, but they do have an impact on vertical permeability, and so we consider their impact on vertical permeability. While continued

drilling and production data has resulted in some revisions to the anticipated extent of the major correlatible shales, the changes that we have seen have been toward less shale continuity rather than more as has been suggested in the newspapers and suggested here today. This next figure is an example of that. The Main Sadlerochit Reservoir productive limit is shown by the dashed line. The shaded area shows the aerial extent of the uppermost correlatible shale within the oil column of the Sadlerochit, based on our pre-production interpretation, the 1976 interpretation. While the cross-hatched area shows the current interpretation of the extent of this shale. In general, you can see that the shale is now believed to be much less continuous over most of the reservoir than we previously thought. The decreased shale continuity should increase the efficiency of the natural recovery process which has been discussed predominantly gravity drainage. You'll notice that both interpretations show that the shale is quite continuous in the extreme eastern portion of the reservoir where two similar shale complexes have served to isolate portions of the oil column from gas cap pressure support, similar to what we described awhile ago between -- with the perforations between the two shales. Consequently, greater than average pressure declines and increasing gas/oil ratios have been observed in this small area. I want to emphasize that this performance was expected because we have included

the effect of these shales in our model studies for many years. It's through monitoring actual performance and modeling performance in terms of pressure behavior and gas/oil ratio behavior that we confirm the extent and the continuity of shales such as this. They are mapped -- these shales have primarily been mapped based on well information, you notice the indentations on the log where the shales exist, and through that and through geologic depositional studies, studies of the history of what was going on when the sand was deposited, that and well data is what's used to develop these maps and we confirm them through observing pressure, production history and modeling. The -- okay -- I think we -- as Brian mentioned, we have seen greater than average pressure decline and increasing gas/oil ratios in that eastern area. Okay, and I want -- the next figure I want to go to then is a predict -- is the measured -- it should be -- it's similar plot to the one Brian showed and it's going to be hard for you to read, but..ah..you saw a little more closely awhile ago, it's the measured pressure drawdown from original in the reservoir. The lines, again, represent contours of equal pressure drawdown as measured at the producing wells. As Brian pointed out, the pressure drawdown in the producing intervals is somewhat greater than the average drawdown if you considered the entire thickness of the oil column. Overall, we see that the oil rim is demonstrating excellent

gas cap pressure support. As you can see, the pressure drawdown varies from about a 100 psi in areas of low production to some 600 psi in this eastern segment of the area -- reservoir where the shale complexes restrict gas cap pressure support. Okay, turning then to the next view graph, that -- that was a picture of measure performance, the same picture basically that Brian showed earlier. This is the pressure behavior observed in our 1976 model prediction, the three-dimensional model that we talked about. The simulator has predicted both the shape of the pressure contours and the approximate magnitude of the pressure drawdown. And in fact, where Terry has his pencil now, you can see that the pressure drawdown predicted, at this point in time, maximum, was 700 psi, so it's slightly greater. We go from 100 to 700 on the predicted as opposed to 100 to 600 on the measured. The inset on the chart compares the predicted April, 1979 average reservoir pressure of 4135 psi to the observed value of 4155 psi, indicating very similar, but somewhat better pressure performance than predicted. You can see these pressures, the original pressures, these are pressures referenced to the original gas/oil contact at a substantive depth of 8578 feet and the original pressure was 4335, so it represents a pressure drawdown to date of a little less than 200 psi. Okay, the next figure compares historical production performance to the model prediction and shows the

predicted performance for the next several years. The oil production history is identical because we produced the model at actual field rates. As you are aware, the TAPS pipeline owners have announced recently that pipeline capacity will be increased to about 1.5 million barrels a day by the end of 1979. Actual and predicted gas production rates are also shown on the chart. As Brian pointed out earlier, the operators have considerable latitude in controlling the amount of gas production at Prudhoe Bay. The model has actually predicted slightly higher gas production rates than actual. The field gas production is currently about 1.1 to 1.2 billion cubic feet per day, which is quite close to predictions. As shown, an increasing trend of gas production is expected in the future. Such performance is normal for an oil field like Prudhoe Bay with a large overlying gas cap. As the oil is withdrawn, the gas cap will expand and override along the top of the reservoir and under major continuous shales, resulting in the increase in gas/oil ratio. The lower curve shows water production which is currently quite low, as expected, and is forecast to gradually increase with time. The upper curve is a plot of actual and predicted average reservoir pressure versus time. And as I mentioned earlier, the measured pressure decline agrees quite well with the predicted. The fact that reservoir pressure has declined only about 200 psi to date supports that the expected

efficient natural depletion process of gas cap expansion and gravity drainage is dominating over most of the reservoir. Indeed, if an inefficient, solution gas drive type mechanism were dominant, as some have suggested, the pressure decline to date would be in the order of 400 psi, or about twice the measured value. Okay, with that comparison of the measured and predicted performance as a backdrop, I would like to -- turning to the next figure, I'd like to review the results of the studies which were presented at the Oil and Gas Conservation Committee Hearing, and provided the basis for the current operating plan for the Prudhoe Bay Unit. Testimony presented at that hearing indicated that ultimate oil recovery from the Main Area Sadlerochit reservoir would be approximately 40% of the original oil-in-place with full development and planned oil and gas offtake rates.

BY: MR. MILES

What's full development?

BY: MR. SMEDLEY

Full development means we drill all the wells and install all the planned facilities and it ....

BY: MR. MILES

What are planned facilities?

BY: MR. SMEDLEY

That's what -- I'm going to talk about some of those as I go down this chart. As we pointed out at the hearing, enormous

future investments would be required to achieve that recovery level. The first area that -- that's very difficult to read, that chart, for sure if you could push it down flat maybe. These are the facilities additions, Mr. Chairman, that are inherent in that. Ah -- completing development drilling on 160-acre spacing rather than 320-acre spacing which was basically what was taking place at the time of the hearing, is projected to increase recovery about 4% of the original oil-in-place. The operators have been proceeding with development drilling, as Brian indicated, they have increased the producing well count from about 100 at start-up to about 200 today. However, there are some 300 additional wells which will be required for full development. The drilling and equipping of these wells to produce will cost in the order of $2 to $3 billion. Studies are underway now to evaluate the proper development limits and well density for the fields. The second potential facility addition shown is a low pressure gathering system to allow reduced wellhead producing pressures. The study indicates an additional recovery potential of about 5% of the original oil-in-place. Total cost for such a system field-wide has been estimated at $1.5 to $2 billion. Now, the first increment of this facility was recently approved by the Unit Owners and equipment has been ordered for installation at Flow Station 2 in the eastern operating area in 1982. Other increments must be analyzed,

designed and justified. The study indicates additional recovery potential of about 5% for an artificial lift system at Prudhoe Bay. Again, the cost is estimated to be in the order of $1.5 to $2 billion, and although this system is at a very early stage of planning, we expect to install such a system when needed to maintain production rates. The studies also show a potential of up to 2% additional recovery by injecting the water that is produced with the oil into portions of the Sadlerochit Reservoir which experienced poor natural depletion recovery. Depending on the final design, this system has been estimated to cost in the order of $1 billion. The Unit Owners recently approved funds for the first increment of produced water injection. Equipment for this system has been ordered and we expect the first increment to be operational in the Eastern Operating Area in 1981. The produced water injection system will be expanded as volumes increase and as production performance allows refinement of the waterflood design. Source water injection systems also offer potential to increase ultimate oil recovery. Exxon's studies indicate the additional recovery may be in the order of 4% of original oil-in-place, as shown on this chart. Sohio, on the other hand, has estimated that the additional recovery from source water injection could be as much as 7% of the original oil-in-place, and both of these figures were presented at the hearing and are a matter of public record.

The cost of the source water injection system has been estimated to be in the order of $1.5 to $2 billion. Dave Griffiths, the next speaker will describe studies and tests which will cost in excess of $40 million which the Unit Owners have been engaged in for the past two years to evaluate and design a water injection system. Estimated recovery without these development additions described would be approximately 20% of original oil-in-place. So, the remaining half of forecast recovery depends upon additional facilities and investments which will cost well over $10 billion, just to develop the main Sadlerochit Reservoir.

BY: MR. ROGERS

How many barrels do you get per -- per each percent?

BY: MR. SMEDLEY

Ah..it's about 200 million, in that order.

BY: MR. ROGERS

Thank you.

BY: MR. SMEDLEY

This future investment of in excess of $10 billion compares to less than $4 billion that's been spent on the field development today. These are enormous future investments which must be justified and facilities designed based on field performance data, detailed studies, and economic factors. As I have indicated, the Unit Owners are already proceeding with several of these projects and others are

Owners need to decide soon on a major water injection program. As you can see from this chart, water injection is but one of the many development activities that we plan for Prudhoe Bay Units. Indeed, others may have a more significant impact on ultimate oil recovery. We are moving forward in a prudent manner on all of these projects.

BY: MR. MILES

Larry, the last chart caused me a little bit of concern. I thought — when we began...ah..we began this in the late 60's and early 70's, we were assuming a roughly 45 -- 40% recovery, but was it known that this extra investment was going to be needed to get to the 40%? I'm really....

BY: MR. SMEDLEY

Yes it was and it was discussed that each of these things would have to be considered and analyzed independently that that -- in the context of the overall plan as we envisioned it developing for the unit these measures would be carried out and that recovery would be attained.

BY: MR. NORGAARD

Let me change a word. We knew and were planned and prepared for the facilities. You said investment, I don't think at the time we worked this problem we knew what the investment would be. Only time and inflation and a few other things give us the key to

what the investment....

BY: MR. MILES

....there was never a dollar figure put on it?

BY: MR. NORGAARD

Yes, we had dollar figures but they were terribly, erroneously wrong.

BY: MR. MILES

Until when?

BY: MR. NORGAARD

They were low, like everything we did.

BY: MR. MILES

How much low.

BY: MR. NORGAARD

I'm sorry I really -- I really can't....

BY: MR. MILES

You know -- we're talking about roughly, Larry said 10 billion, how much were we talking about then?

BY: MR. NORGAARD

I would speculate that they were probably half, our estimates were probably half, at that point in time. Well, they've changed....

BY: MR. MILES

What was that point in time, when was it.

BY: MR. NORGAARD

Let's say four or five years ago.

BY: MR. ROGERS

And revenues were about one-quarter?

BY: MR. NORGAARD

Things have changed dramatically all the way around.

BY: MR. ROGERS

You mentioned both on the well spacing and produced water.. ah..east -- the east operating -- are you -- do I get from that you're going to be using as additional recovery earlier in the eastern section?

BY: MR. SMEDLEY

The -- it's planned that the produced water injection will go in early -- one year earlier, as we currently envision it in the eastern section and the west.

BY: MR. ROGERS

Is there any -- since this May, 1977, are there any new technologies that might push us beyond the..ah..40% recovery?

BY: MR. SMEDLEY

Not new technologies, I don't think, but....

BY: MR. ROGERS

Are there new -- ones that have become economic because of the higher value of oil.

BY: MR. SMEDLEY

No, sir ..ah..you're thinking in terms of like a tertiary recovery process or something like this I assume, and no, there are none currently.

BY: MR. NORGAARD

I think the answer to that may be expanded a little bit. I think, that's a continually changing target as people learn more from other areas and also as the economic environment of the world changes, but there's one thing for sure, that Prudhoe was not the place to experiment. It's a high cost area and experimenting should be done in something that's relatively safe and (indisc) so we look very heavily to other similar environments to -- to see what's happening and to ....

(indisc - simultaneous speech)

BY: MR. ROGERS

Sub-surface environments, what areas of the world are similar?

BY: MR. NORGAARD

Well, there are a number of reservoirs that are not dissimilar from Prudhoe Bay -- I went for many years, it's probably too late to try anything with it, but there are a number of reservoirs that you can use as, certainly not parallels, but it's something that you could use as a go by. I don't think that there's another Prudhoe Bay in the world, but there's reservoirs with character in (indisc). Larry mentioned that high quality characters in Prudhoe Bay, there's other reservoirs in the world that same, a similar high quality

(indisc)

BY: MR. ROGERS

Sir, when did you do your first preview runs? When did you

build your model?

BY: MR. NORGAARD

We built the model in 1976 and ran it in 1976.

BY: MR. PARR

I realize that every field is unique, I understand that, but isn't there sort of a general rule of thumb around the world that 35 to 40% of your -- 35 to 40% of your reservoir is recoverable? Generally speaking?

BY: MR. SMEDLEY

No sir, that's how I -- for an overall average.

BY: MR. PARR

I - we've been lead to believe that in previous testimony that -- not necessarily this particular set of hearings, but one we've had in the past. Now, I'm just wondering when I see that 20% on there..ah..did the -- your operators -- your Owner companies ever consider any possibility of only getting 20% and stopping?

BY: MR. SMEDLEY

Yes sir. We have since the very early studies, very early, that's -- I mean, since our studies in the early 1970's where we started getting pretty sophisticated with reservoir modeling and interestingly those days have not changed too dramatically even up to now, since that point in time when I've been involved in this type of work on this field..ah.. the plans for development, the types of things you see..ah..facility

additions and so forth have been contemplated. We never really ever expected to stop development when we had only 320 acre spacing since the -- that was -- you drill 320 acre wells before you drill 160 acre wells, just like you would drill 160 acre wells before you drill 80 acre wells. So, at some point in time we had those kinds of wells, but it was never envisioned that we would stop.

BY: MR. PARR

Let me ask my question in another way then. The impression you gave in going through this chart is that you're going to start off with 20% recoverable and then at each one of these additional capabilities the Owner companies are going to look at this on say a cost benefits ratio, bases or something of that sort, and decide -- you know -- whether it is economically feasible for the company to do it, and so you might get 20, you might decide that only the first 160 acre wells is the one you'll do and stop at 24, or you got down through that one and then you decided it wasn't economically feasible so you might stop at the second item which is 29% and so forth. But, I'm getting -- now, I'm understanding that that never was contemplated and is not now contemplated, is that correct?

BY: MR. SMEDLEY

It was -- the studies weresophisticated enough that -- it was anticipated that we would be able to go to this type of development. In terms of presenting our estimate of recovery

we pointed out that there are alternate development schemes possible, several of which may go after the same oil. In other words, there are different ways to get there. This is one, I don't like scenario, but that's one scenario for getting to 40% recovery. There are others, perhaps involving closer well spacing, 80 acre spacing, this type of thing, and as we mentioned at the Pool Rules Hearing, based on a wide variety of studies where we have varied the reservoir descriptions, would Prudhoe reservoir look like this or will it look like this. We could see that 40% recovery appeared to be reasonably achievable under varying reservoir desciptions, but the way to get there, the best way to get there, was different with different descriptions, and so, we gave the 40% recovery as our best estimate. We left some flexibility in the steps we take to get there and we'll take the optimum steps as we learn more and more about the reservoir.

BY: MR. PARR

In other words then, it may not really cost the $10 billion to get that 40%? You might take some other steps which don't cost that much money, is that correct? You got $10 million, this isn't that short that you told us, but you just said that there are other possible ways to do it.

BY: MR. SMEDLEY

That's right. It is conceivable, and on the other hand it's also conceivable it may cost way more than $10 billion.

BY: MR. PARR

Let me -- in other words, if you don't use the systems , the steps shown here, if you use other ones that may not even cost you the $10 billion.

BY: MR. NORGAARD

Let me offer an comment here if I may, I don't like to interject myself, but I think that as far back as we go in the direct testimony before Conservation Committee, yourselves, federal government and whatnot, the plan for the field has always been to fully develop the field, and when we say fully develop the field, that means doing essentially all of those things, include waterflooding. That has been the plan and it -- you probably -- the May, '77 hearing, we said that we were proceeding along that plan, we just needed some production history to verifying certain things that we had speculated and therefore we have always planned on doing all of this. The exact timing and the exact sequence, that's something we will learn as we go, but the plan has always been to do all of that, we have always looked for 40% recovery and this is just one way of isolating and saying this is what each of these contributes. It's almost an academic exercise in a certainty.

BY: MR. PARR

Thank you, that's the kind of answer I wanted.

BY: MR. MILES

When -- Paul, as long as you're

in this discussion, when do you plan to begin waterflooding?

BY: MR. NORGAARD

Well, the -- thing you deal with is what does waterflooding mean and when we begin to inject water -- no, when we plan to begin injecting water into the producing formation will be in 1981 and it will be in the Flow Station 2 area, the area where we have seen the greatest pressure, highest continuity in shales, therefore the most obvious and logical place to start waterflooding.

BY: MR. MILES

That's just a - that's just a little trickle in comparison. I mean, that's just a -- what Dr. vanpoollen said, the goop that comes up, goes back down to 100 thousand barrels (indisc. - simultaneous speech)

BY: MR. NORGAARD

And it could be when we get there, sir, we will choose to augment that in some fashion. We're looking at that and we'll continue to look at that. When we would be looking at going to a major outside source ....

BY: MR. MILES

.... Yea, that's what I'm ....

BY: MR. NORGAARD

.... the earliest possible would be in '84, and Dave Griffiths will give you a lot of detail on that in just a minute, but the timing that you ask, would be the earliest possible is

'84 and that's certainly our objective, unless something trips us up very badly between now and then.

BY: MR. MILES

Thank you, that's the objective, but.....

BY: MR. NORGAARD

There's no way that we see we can get there before '84.

BY: MR. MILES

What might trip you up?

BY: MR. NORGAARD

A permit application, just physical constraints, and material delivery times. The -- some very, very strange reservoir interpretations between now and then. We've done a lot of work, but we still have a lot to do, i.e., history matching and carrying forward that..... Those are the three main areas and Dave Griffiths will speak to each of those in some detail.

BY: MR. MILES

It's costs -- costs are not a main factor.

BY: MR. NORGAARD

I'd have to say I don't believe right now -- I'd have to look at it again, but I don't believe right now that the cost or who -- how it's financed is material at all. We really are worrying the permit problem -- the design problem and materials and then finally the reservoir analysis problems. And I think in each of those, we are targeting ourselves so that

they coincide, we hope, about a year from now, we'll consider it a year from now, and at that point in time everything will fit and we'll move forward.

BY: MR. MILES

Thank you very much.

BY: MR. NORGAARD

But, Dave will elaborate on that point.

BY: MR. CHATTERTON

Yea, I'd like to go to Larry for a minute, if I can. In your 1977 presentation in May, I've always had a little bit of a problem with these two charts because you also testified that that primary recovery while you were anticipating about 36% recovery, yet you got 20 down there. I think you were trying to sell well spacing with that one, and you were trying to sell that you were going to recover a lot of oil with the other guy that testified. I've never been able to correlate the -- this chart with your other statement, not yours personally, but other statements made by the operators, that the primary recovery is going to be 36%, waterflooding ultimate recovery is going to be 4% -- 40% and of course, obviously, the 4% differential is not any great, horrendous incentive to proceed to that point, but I've never been able to figure where you get the 20.

BY: MR. SMEDLEY

Okay, let me try it, one more shot at this thing. Ah..the reason for this chart is to show several things that are

reasonably similar decisions that have to be made, that are being made, but in a logical course, to get from where we are right now which is with adequate facilities and wells and so forth, to get about 20% of the oil-in-place out to where we think we will end up and that is with wells and facilities and so forth to get 40% of the oil-in-place. So, it's -- really its primary intent is to say it -- waterflooding is one of the decisions we have to make, in terms of money the inference is that we're not willing to make that decision because it's a large capital investment. These other items are equally large capital investments.

BY: MR. CHATTERTON

How do you get from 20% to the 40%, what else can you do there?

BY: MR. KOONZ

This is primary recovery here.

BY: MR. CHATTERTON

I understand, and if you say it's 36% in your testimony (indisc.- simultaneous speech)

This one always just confused the hell out of me.

BY: MR. NORGAARD

I don't -- you're alone in that. I think the main thrust here is that the 20% is not a primary number. The 20% is a primary number under a given set of assumptions and that assumption is that we don't do anything more in Prudhoe Bay.

BY: MR. CHATTERTON

....The oil in 1977, I think....

BY: MR. NOORGAARD

....what,no, if we don't do anything more in Prudhoe Bay, that right now we quit. Matter of fact, that was in 1977 that we quit.and that's an unrealistic assumption. We all know that's unrealistic and therefore, this was an attempt to say there are other options or there are several requirements to get the primary recovery out and this is a listing of them and what we suspect will be recovered with each one of these. Now, there's another point here that those numbers, the fours and fives and whatnot, are certainly not rigorous because when you do all of those things they're interrelated and you can't say which barrel of oil was recovered from which one of those phenomena. That is just a guide in how much oil each of these will deliver to the tanks. Now, did that help?

BY: MR. CHATTERTON

That helps. I think the point that you've made is the important point, that that 20% was your estimate of the recovery from Prudhoe Bay in May, 1977 if you walked away and did nothing more.

BY: MR. NORGAARD

We did no more, put no more money into it.

BY: MR. CHATTERTON

....but with continued development drilling, continued with waterflooding, continued with this and everything as you are,

you could get to 40%, if, with waterflooding. Without waterflooding you would only get the 36% and your testimony, if you correlate it in that fashion fits, but your explantion did not.

BY: MR. SMEDLEY

The way I would have walked down through that is to say, alright, we were at 20% recovery by drilling the additional wells, get down to 160 acre wells which is some 500 in the field, we will get up to 20+4, 24, if we -- by adding a little pressure gathering system, we get up another five to 29. By adding an artificial lift system we add another five we get up to 34, that's the natural depletion recovery without produced water returned to the reservoir. If we return the produced water to the reservoir we get another two, that's the 36 (indisc - simultaneous speech)

BY: MR. CHATTERTON

There you are, okay.

BY: MR. MILES

I told you Chatterton was the only one who grasped this.

BY: MR. MILES

But he asks leading answers.

BY: DR. DOSCHER

Mr. Miles, may I ask one clarifying question? You didn't mean that you'd walk away in 1977, you meant completed at 320 acres, didn't you.

BY: MR. SMEDLEY

Yes, that would be with some 200 and some odd wells for 320 .....

(indisc - simultaneous speech)

BY: DR. DOSCHER

Fine, it didn't mean that -- it didn't mean to stop cold in 1977.

BY: MR. SMEDLEY

That's right. It was 320 acre development, if you stopped at 320 acre development.

BY: MR. ROGERS

Since, since a number of these methods are pretty high cost, and you're talking about $2 billion each on the average and some of them, I don't know which ones, waterflooding apparently is time sensitive, the earlier the better, and I don't know -- I don't know about the others. And, is the -- since the recovery comes later on, it's not going to be a early recovery, obviously, your cost is higher, your internal cost is higher if you do it sooner than if you -- you hold off for a year even though the recovery might be higher if you did it sooner. I guess -- since the State's discount rate is probably lower than the industry, if the State were to offer to participate in the financing would that speed up any of the..ah..any of the secondary recovery techniques.

BY: MR. NORGAARD

I think the answer to that is basically that we are on a

critical path right now. Ah..with '84 as being the earliest possible start-up to take things in a logical sequence and we would have to look at it closer than what we have right now, but the general answer was no it would not speed it up.

BY: MR. ROGERS

So, you're saying then that the financial aspects are not the limiting things on..ah..I'd say waterflooding, it would be equipment or materials.

BY: MR. NORGAARD

That would be the case at this point in time, yes, as we perceive it right now. Come 1980 though, the answer might be a little different, if something strains, if the purely unforeseen happens between now and then. We don't visualize -- we don't envision that the plans for water injection, we fully expect to moving forward in 1980.

BY: MR. McKINNON

Can I ask four questions, if I may. When you do your economic analysis, cost benefit, what discount rate do you use for the industry?

BY: MR. NORGAARD

That's -- that's really an impossible question to answer in many (indisc.) because first of all there's three companies involved and therefore, there's probably three different considerations, but certainly industry in general, and I believe that they have testified, several of our companies,

have testified a number of times in a number of places, we do look at discount rates, we are looking at discount rates, they're basically industry averages, if you will, which is really not just oil industry but total domestic industry -- you know, all industry, automobiles, everything else and that is influenced, of course, by the value of money, what it costs to borrow and so it varies depending on which year you're talking about and I believe, that this particular point in time, it's somewhere 13, 14, 12 somewhere like that, is the kind of numbers that industry is looking at..ah.. in generating good prospects in moving forward. I really don't know what the prime rate is right now, but I think it's over 12. It varies, and I don't think that there's a pat answer to that question.

BY: MR. McKINNON

Your economic analysis doesn't use an average for the industry, it uses an average -- an average for the oil industry, you use an average for industry in general.

BY: MR. NORGAARD

Again, I think the economic analysis each company has its own, but in general, for -- they would be reflected.

BY: MR. McKINNON

What is your companies....

BY: MR. NORGAARD

To be very honest, I can't give you answer on that right now

because again it's a changing thing and I really don't know what it is. That isn't the only criteria, that isn't the only parameter that goes into the decision making property and I'm not in a level in our company where I can give you all the answers because I really don't know. But certainly, I'm going to step - take a step further than you questioned, if I may, and it goes into what -- at I and I think, we as oil companies perceive them in Prudhoe Bay field. Ah..several questions have come forward here with respect to the rate of return and the difference the State has versus what industry has in their rate of return criteria and there can be instances and there probably have been and will be instances where that does create differences, different desires, different objectives and different opinions. I would be naive not to say that that is true. I think in the Prudhoe Bay Field, though, we happen to be very fortunate, in that the reservoir is a high quality reservoir. The work -- at least I heard from Dr. vanPoollen and Dr. Doscher also mentioned, the work that we have seen suggests that the decision process and the decision timing that we're going through on this, is not sensitive to these discount factors. It appears as the reservoirs are -- sufficient quality, the decision appears to be, like it will be clear enough so we won't get into difference of opinion or conflict because of the discount rate. Now, I can't guarantee that, but that's certainly what I

heard from Dr. vanPoollen and I believe from Dr. Doscher, and tied to our own studies we're talking about at this point in time. Our plans are to waterflood it as early as -- we physically can do that. I think that is consistent with everything I heard and now I can't guarantee that's what is going to happen because a ducks could fall on the road between now and 1984, but that certainly is what we expect.

BY: MR. McKINNON

At what point -- is..ah..what point does waterflooding become economically unfeasible, in some point it's just not worth doing?

BY: MR. NORGAARD

You know -- again, I'll answer it. It's a technical question but I'll answer it because I really think it has overtones in it. If you can predict to me what the world is going to be in 1990, I might be able to answer your question. I don't think that there is a point in time when one can say. It's uneconomic to waterflood a reservoir or a facility because it's tied so much to what it's going to cost, in what the value of the product your going to get and therefore, I don't think we can sit here today and..ah..make a realistic prediction. I think we can say though, and I believe it will be said later on, that in the realistic environment waterflooding within any time frame that we could realistically accomplish it or that we would consider, has simply no impact on the

Prudhoe Bay performance and I believe that's what you're looking for in your question. In other words, whether it's in '84, or '86, or '87, it realistically has no impact on Prudhoe Bay on the recovery from the field, that we've been able to see, and if I understand -- I mean, if what's been done in that's true of what other things?

By; MR. McKINNON

If you start water injection in 1984 it's going to get you an extra billion -- billion barrels.

BY: MR. NORGAAR

....pick a number...

BY: MR. McKINNON

....you start at 1985, it's not going to get you a billion barrels.

BY: MR. NORGAARD

Well, you've gone outside, I believe, the realistic range ....

BY: MR. McKINNON

....that's what I'm trying to understand, what the range is.

BY: MR. SMEDLEY

There were study results presented at the hearing, I know we varied the timing of water injection, as I remember, we're going into these in just a second from..ah..five to nine years, so that would be , like, it'd be in '86. Other companies, I think ARCO presented a study where they delayed the start for like fifteen years. At nine years there is

essentially no -- we got essentially the same benefits from water injection that we got with earlier cases, at fifteen years it was a little less but I don't remember exactly how much less, but it wasn't a great deal less, but it was -- in both cases -- alright, if you wait, one of the things that will happen -- you know -- water injection offers really two benefits as we see it, it's a rate maintenance benefit by -- you can maintain the production plateau, whatever that production plateau, 1.5 million barrels a day, we're talking about longer -- it offers some benefits in that regard and also offers some additional recovery benefits, I think we've talked about. If you wait past the point that it -- production plateau has already dropped off, you've gone in decline portion, then -- and this is the way in previous times, waterfloods were typically implemented. You see a production response, production goes from low to higher..ah..so that's one of the differences that you see with a delayed one is you actually show an increase in production, whereas, if you start before the end of the plateau period it's an extension of the plateau. But the impact on ultimate recovery has been shown to not be very sensitive to timing of the start. Its much more sensitive studies indicate to where the water is injected to getting the most efficiency out of the water you inject.

BY: MR. NORGAARD

And that -- that is the key point that you're probably going

to get to later, but that is -- you can make a bigger mistake by putting water in the wrong place than you can by waiting too long.

BY: MR. SMEDLEY

Okay, the next view graph summarizes some of these studies that we've just talked about..ah..these are....

BY: MR. MILES

Larry can I interject just a second, we had originally planned to break at 5:00, we haven't had any word from the second floor one way or another, so I think what we'll do right now is, I understand a number of people have early evening planes 6:30 plans to catch, I think what we'll do is go through until 5:30 and Paul try and finish up with your presentation. Assuming we haven't adjourned by 7:00, we'll come back, anybody who cares to come back, those people from out of town with planes to catch, I don't expect them to come back, I mean you folks have gone above and beyond as has this committee, I think. A number of us are interested in continuing the discussion. To me it's been -- I've learned as much in the last two days as I had in a year, I think, from just the give and take. There are a couple of other people who indicated that they wanted to testify, 7:00 presuming we haven't adjourned..ah..we'll give those folks the opportunity to testify and then again presuming we haven't adjourned, I'd like to just sort of open it up to a general discussion. Ah..

it's a pretty loose way to run an operation, but it -- I think after we adjourn, everyone will be drunk. There won't be too much we can do after that. That's sort of the setup and right now if people have to leave fast at 5:30, I'd certainly like to thank everybody.

[Discussion re time schedule]

BY: MR. SMEDLEY

This..ah..as I indicated earlier in this hearing, because of the large number of cases that were involved in our sensitivity studies, we ran these cases with our -- with basically a two-dimension -- it's really a three-dimensional model but it can best be classified based on what you've learned in the last couple of days as a cross-sectional model of the reservoir. The field-wide three-dimensional model that we've described and we've shown the history match compared to, was used to verify the cross-sectional runs. But the results we presented at the hearing and that we are presenting here, were run on a cross-sectional model which was proven to be by the three-dimensional model an adequate model for looking at these sensitivities and for predicting the ultimate recovery for Prudhoe Bay. Cases that we looked at with oil offtakes

ranging from 1.2 to 1.8 million barrels of oil per day showed no significant effect of oil offtake rate on ultimate recovery. These cases that are shown on the chart were run with produced water injection and two billion cubic feet per day of gas pipeline deliveries commencing after five years of production. The second sensitivities shown investigate the impact of gas pipeline deliveries beginning in 1982, or five years after the start of oil production, compared to delayed deliveries. If we only injected produced water, a 10 year delay in the gas offtake from 1982 to 1992, increase recovery only slightly, from 36.2% to 37.5% of original oil-in-place. Studies show that with appropriate modifications to the reservoir management plan, we can offset this relatively small impact of gas deliveries on oil recovery. One method of offsetting it is with source water injection and it's just shown in the next cases, with source water injection and gas deliveries commencing in 1982, recovery varied for different cases from 39.3 to 40.2% of original oil-in-place, this depended primarily on the level of water injection, this compares to 40% recovery with gas deliveries commencing in 1987. So that was comparing '82 versus '87 deliveries. As you're aware, progress has been slow on the proposed gas pipeline. Consequently, we now believe that 1985 is the earliest likely timing for gas deliveries from Prudhoe Bay. The final results shown on this chart represent the sensitivity of

ultimate oil recovery to various water injection programs. With natural depletion supplemented by produced water injection, a recovery level of about 36% is predicted. This relatively high recovery without source water injection is due to the favorable rock properties that we described earlier from the view graph, which provide for efficient gas cap expansion and gravity drainage over most of the reservoir. The studies show that source water injection commencing in 1982 to 1986 with rates varying from 1.7 to 2.5 million barrels per day offer potential to increase recovery to about 39% of original oil-in-place, this is the nine year case we were talking about, 1986 starting up. Larger water injection programs that were analyzed commencing in 1982 and 1984 resulted in recoveries of about 40%. The studies indicate that ultimate oil recovery is not very sensitive to the timing of injection start-up within reason and within the range as shown. Cases with injection beginning later result in the same recovery if we increase the rate of injection to "catch up" with the earlier injection program. Now, this is because the major benefit of water injection at Prudhoe Bay is improved conformance or sweep efficiency rather than pressure maintenance. Therefore, it's more important to select proper injection locations and volumes than is the timing of injection start-up. Decisions on the proper injection locations in this complex and diverse field will

require substantial performance and testing data as well as detailed studies. As Paul mentioned earlier, there is too much risk of reducing recovery if we were to proceed without sufficient data and we injected water at improper locations so as to impair gravity drainage where it is the most efficient recovery process. Indeed, the risk of reducing recovery by improper water injection more than offsets the potention risk of deferring the start of injection. With the natural depletion process being very efficient, we believe there is time available to obtain the necessary data and perform the required studies and still be in a position to initiate waterflooding so as to achieve maximum oil recovery benefits. I'll hit briefly the final chart which basically summarizes our conclusions. First, that the Operating Plan studies submitted at the May, 1977 Conservation Commission hearings are still valid. Field performance and testing hasn't significantly changed the outlook that we provided then. Secondly, the oil and gas offtake rates approved by the Oil and Gas Conservation Committee in Conservation Order No. 145 are consistent with achieving maximum economic recovery from the Prudhoe Bay Field. And finally, the ultimate recovery estimates of 40% for oil and 75 to 80% for gas still appear reasonable. However, achieving this recovery will require enormous future investments. These investments must be evaluated and justified individually, considering such

factors as the amount of additional oil to be recovered, the value of the oil , associated operating costs and taxes. Additional production performance and testing data is required before many of these decisions can be finalized. Now, that concludes my prepared testimony and we're aware of your keen interest in waterflooding and what we're doing with regard to studying waterflooding at Prudhoe Bay, so Dave Griffiths of ARCO is now going to give you an update on the progress of our waterflood studies.

BY: MR. CHATTERTON

Thank you Mr. Chairman. Larry, I appreciate the constraints of time and everything else, but there's one thing that I would like to rap with you on. I realize that you are representing 16 participants here today and that there are 16 participants, I presume there's 17 different ideas on everything, as 17th being what you're presenting, the consensus opinion and I appreciate that, but let me follow through a little bit. The thing that has bothered me for a long while is the small -- well, let me put it this way, the expected high natural depletion recoveries of 36% and the small differential between that and full scale of 40% everything. Now, that expected natural depletion, I've been told anyway, was due highly or one of the very major factors and it was gravity drainage. Do we still today, I mean, having watched what's happening, still believe that it's going to be a very overriding

mechanism in the recovery?

BY: MR. SMEDLEY

Yes sir, we do. And in fact, we have developed some more sophisticated models than the one I described to you today. The impact of the one today was to go back to its earlier developed model. These models, in order to get a very precise match of history, indicate that the shales that we have built in the models are less continuous or the shales are actually less continuous than we built in the models, they indicate that the permeabilities, in order to get a good pressure match, are somewhat higher than was originally anticipated, so the properties as we would analyze them right now today are more favorable for that mechanism than two years ago.

BY: MR. CHATTERTON

And this, if I may Mr. Chairman, is this in view of the fact that you've showed us a slide today which is the same as you used in '77 that showed the KBKH ratio as being extremely low, you also mentioned that even in '77 you knew about these major shale breaks. Do you still feel you've got an excellent vertical permeability?

BY: MR. SMEDLEY

That's right. The vertical permeability -- I think we probably concentrated far too much on that small portion of the field over there where the shales are very continuous, gravity

drainage won't be efficient in that area, for sure, where we saw the big pressure sink, but over most all of the field, it's going -- it appears to be very efficient.

MR. CHATTERTON

Thank you, thank you Mr. Chairman.

BY: MR. NORGAARD

I think one of the thing is that the..ah.. permeability levels in the reservoirs are very high, so even though you have KBKH that..ah..is less than ideal, you still -- the permeability available in the vertical direction is very high.

BY: MR. PARR

Mr. Smedley, I got into a little thing awhile ago there with you and I thought you sort of made me feel a little better about it, but then your last paragraph, you go back to the statement, comes back to the same point I was raising. You're going to take each one of these things and evaluate it and so forth before you apparently decide to do it. You may not intending to go for 40%. You read the last few lines of your statement you just now read. That's exactly the point that made me raise those questions earlier. You know, I mean is -- are the producers planning to invest this money and shoot for 40% or are they not. The original targets were 40% oil and 75% gas and that was still valid, then you said each one of these additional things have got to be studied and evaluated and I guess costed out, I don't know

what, your own words out of your own statement a few minutes ago which indicates or implies at least, they may not be done, right? And I don't know.

BY: MR. SMEDLEY

I think both parts of your statement are basically true. We anticipate that they will be done, it is our best estimate that they will be economic. They will be evaluated independently, they do have to meet our minimum investment criteria, we do not believe that we serve the consumers in -- of the country by making uneconomic investments.

BY: MR. PARR

What I'm coming back to -- laying down to the sort of bottom line, to use the jargon, there may or may not be an attempt to get out 40% if the producers decide that one of these steps you listed is uneconomic, it will probably not be done, therefore those percentages would fall out unless you find some other way to handle it. Is that correct?

BY: MR. SMEDLEY

All of these are decisions that have to be made, some of them have been made, we indicated we're already proceeding with several of them, we fully anticipate that they will be made based on our best studies today. Those decisions will be made and affirmatively made, but in a grosser sense, I think what you're saying is proper.

BY: MR. SHOWALTER

Yea, I would try to answer your question with a question to you

BY: MR. MILES

I said no, you're supposed to answer these questions.

(indisc. - simultaneous speech)

MR. SHOWALTER

Do you anticipate that the ferry system schedule in Alaska will be exactly like it is today in 1985 and are you willing to make that decision today or will you examine the budget for the fiscal year '85 when it comes up and decide how much funding you're going to give to the ferry system. I think it's a very similar thing.

BY: MR. PARR

Well, I don't think so at all, Mr. Showalter. I -- I never expected Exxon or ARCO or BP or anybody else to operate at a loss; nobody would expect me to run my business at a loss. I never -- I never expected that, but the impression was being given to that and that's what I wanted confirmed, either it is or is not, that these things are not firm. They're firm if they're economically feasible for the producer company, is that correct?

BY: MR. SMEDLEY

That's correct and these other things in that sense are in the same boat as the water injection system. They're all investment decisions.....

BY: MR. PARR

.....but now we understand one another. These things are all

contemplated if the producers decide they're economically feasible, they will be done.

BY: MR. SMEDLEY

We believe, based on our best current estimates, that they will prove economically feasible.

BY: MR. PARR

I said but that's your -- that's an estimate, there's no guarantee of any of that.

BY: MR. SMEDLEY

That's right.

BY: MR. PARR

That's all I wanted to get clear.

BY: MR. NORGAARD

Let me just say one thing that I think is consistent and compatible with this, until the owner companies have authorized the expenditures for whatever lies in the future, and that could be the next well in Prudhoe Bay, there's nobody that could say it will happen. Once the expenditure has been authorized, we can say it will happen. We can look at the plan and say that is what we think will happen. I think we can go a step further. I think I can say that the decisions will be easy, but I don't think there's anyone who can say until the major companies and a proper vote has been taken that this will be done. It does take the senior management of our companies to say that it's a proper expenditure before

HOUSE RESOURCES COMMITTEE MEETING

ON

PRUDHOE BAY RESERVOIR MANAGEMENT

ROOM 118 - CAPITOL BUILDING

JUNEAU, ALASKA

August 6 and 7, 1979

Volume III

Pages 301 - 334

J & R Associates

P.O. Box 29 • Douglas, Alaska 99824

Judy Jones
586-6846

Rita Stoinich
789-0208

AGO 532414

we can make it, but we believe in everything that we've done, and I'm speaking for ARCO right now, that the decisions are easy, they're not tough decisions. Now does that help?

BY: MR. PARR

I think so, thank you. I think we understand where each other is coming from now and it is all clearer now that this is not -- anything guaranteed at this point.

BY: MR. GRIFFITHS

Thank you, Mr. Chairman. My testimony will last about 20 minutes if I go through it rather hurriedly, so with your permission, I'll take off. If there are any questions why somebody (indisc.)

BY: MR. MILES

Before you start so you don't get interrupted, if anybody has to take off to catch a plane, I know we said we'd stop at 5:30, it's almost 5:30 now. Anybody besides you, Mr. Griffiths? Okay, let's go.

BY: MR. GRIFFITHS

Members of the House Resources Committee, ladies and gentlemen, my name is David Griffiths. I received a Bachelor of Science degree in Petroleum Engineering from the University of Texas in 1958, and was employed by Atlantic Richfield as an engineering trainee. Following three years of military service, I rejoined ARCO where I have had a number of reservoir production engineering assignments. Since moving to Alaska in 1974, I have been directly associated with North Slope activities.

For the past two years I have been a member of the Prudhoe Bay Unit Planning Subcommittee, which has had the responsibility of coordinating the waterflood studies which have been conducted in the Unit. During the next few minutes, I would like to discuss the progress of the waterflood studies that have been underway during the past several years. I will briefly reflect on the work that has been done to date and describe the current status of the waterflood project. Following this, I will outline the future waterflood project plans as they are now envisioned. Between 1969 and 1974, several waterflood feasibility studies were undertaken by ARCO, Exxon and Sohio. The studies led to these conclusions, first a waterflood system for Prudhoe Bay is mechanically feasible; second, the most probable source of water is the Beaufort Sea; and third, field performance history is needed to properly design the system. Work done between 1974 and 1976 established eighteen engineering studies that would need to be undertaken prior to completing the conceptual design of a waterflood system. Such studies would include analysis of water source, freeze problems, soils and permafrost; ice; weather, materials selection, water treatment, and more general project interface studies such as environmental and permitting requirements, project planning, and cost estimating. While many of these study areas were common to many waterfloods, some were unique to Prudhoe Bay.

Following the formation of the Unit, owners have maintained an aggressive program to resolve questions regarding the viability of a waterflood. This effort has proceeded on two fronts; one, improving our knowledge of the reservoir and secondly, developing a waterflood design. As has been mentioned, reservoir studies have recognized the potential benefits of returning produced water to the reservoir and of supplementing the produced water with source water for some time. Estimates of additional oil recovery ranged from four to seven percent of the oil-in-place. We recognized that production history would be needed to verify the need, locations, and volumes of waterflood. We identified areas of engineering interpretation, such as fact efficiency, stratification in the reservoir, and injection of well capacity as important factors affecting the expected benefits resulting from waterflooding. In addition, early in the reservoir study period we recognized the effects of geological factors such as faults, the heavy oil/tar mat, shale continuity on the selection of flood location, volumes and flood performance. As as example, shale continuity is perhaps the most important geological factor affecting choice of recovery mechanism and it's the most discussed here today. The two most efficient recovery mechanisms available, gravity drainage and waterflooding, are each capable of higher than average recoveries in particular areas of the field. Normally,

gravity drainage works better in thick oil columns which have no continuous shale barriers blocking oil movement, while waterflooding works better where the oil column is broken up by continuous shales into several isolated layers. It is vitally important to identify areas where gravity segregation is most effective prior to injecting water. If water is injected into areas where the shales are discontinuous, the waterflood recovery will be poor and the more effective natural recovery mechanism will be eliminated. On the other hand, if the shales are continuous, gravity segregation will be less efficient than waterflooding. However, reservoir studies show that even in these areas the ultimate recovery is effectively unchanged with a minor delay in initiation of waterflooding. Consequently, it is far more important to know where to waterflood than when to waterflood. Since shale continuity is such an important factor, a group composed of....

BY: MR. MILES

How can they determine -- if that's true, how can they determine for example like we've heard earlier in Alberta, where waterflood prior to a field going into production.

BY: MR. SMEDLEY

Let me try and take a shot at that. Ah.. frequently, that's done -- you don't have the same situation like the one that I'm most familiar with because it's an Exxon field, is J Field in Florida which other than Prudhoe is the most

significant discovery in recent times. We -- decided to waterflood J very, very early and started water injection essentially at the start of production. It was -- it had no possibility of good efficient natural depletion mechanism. It was..ah..I don't want to get into the technical terms, it's natural recovery would have been very low, nothing like in the order of 30's% like we have at Prudhoe, it would have been like less that 20% and so, there wasn't this option to trade off -- you know -- to -- maybe, the natural mechanism may be more efficient in some areas at least than an induced mechanism.

BY: MR. MILES

Even -- almost setting the recovery level aside, if it's more important to know where to sink that hole as opposed to when, don't you have to have some kind of a production history, I mean (indisc - simultaneous speech) We keep hearing that everything has to be done based on production history..ah.. and this seems to fly in the face of that..ah..so, I guess I don't understand, even if the -- even if your -- you know -- the best hopes without waterflooding are only 20%, it seems like, at least from what we've heard, you'd have to know the dynamics of the field prior to -- prior to sinking a water-flood well.

BY: MR. SMEDLEY

It depends -- its -- every reservoir is so different and so

unique..ah..if it's purely a pressure maintenance thing, if your putting the water in, many times the water is just injected out in the aquifer out in the natural water bearing part of the reservoir, not even within the oil part of the reservoir. Okay? Just purely for pressure maintenance because the reservoir would not do well if you didn't inject it, like at J. The pressure -- in the first year of production at J, for instance, here we are talking about a 200 psi pressure drop in two years, at J the pressure drop would have been thousands of pounds in this period of time. An order of magnitude difference. So, the need was obvious, the injection -- so the injection was started Ah..and it was done -- the reservoir properties were such that you didn't have this concern of -- you know -- messing up an efficient natural mechanism in some parts of the reservoir by injecting in others. You had -- you had a very poor natural mechanism you couldn't foul it up any worse than it was -- you know. Face it, you aren't going to get hardly anything if you didn't do something.

BY: MR. NORGAARD

Let me offer a comment on that, too, if I may, Mr. Chairman. I think we can go to a very close Alaska scene, the Trading Bay unit. There is an utter saturated reservoir; it has no gas cap and therefore, you can determine very early that primary recovery will be low and you can take rock samples and very quickl

in the laboratory analyze it and see what the expectations would be if you waterflooded and you can determine very quickly and very early that you have a natural and logical candidate to waterflood. The waterflood is initiated in Trading Bay unit, I believe, within three years. It was -- you know -- as fast as they could physically get equipment. And, in that you just have a single mechanic, just a single mechanism, it's solution gravity -- it's solution to drive system where you just have rapid fluid expansion. Very simple. You can look at it, you can analyze it and you've got, probably 20 other reservoirs that you can hone in on immediately that are similar, and you just need to get some laboratory data of the rock itself and the fluids themselves and you can go. Canadian reservoirs could be that same kind of thing. In Prudhoe you've got a very complex field. You've got several mechanics working simultaneously, you need to determine how they are working, how they're interrelating, how the -- and the locations of the interrelation. So you do need some time to look, I would speculate also that the fields in Canada are generally very small and they have a sister or a cousin that are pretty close by. You know -- there's a lot of oil fields in Canada and there's only one Prudhoe -- you know -- it's very difficult to find a sister or cousin, but there's an awful lot of oil fields in Canada where you could be looking at a sister or cousin right next door. You know -- just the day you drill it, you can say, gee

that's exsand (ph) -- exsand well that works this way, so we'll do it. I think, I'd turn to Dr. vanPoollen for a probably a better explanation than that.

BY: MR. MILES

Do you care to comment?

BY: DR. DOSCHER

The story is if you have a gravity drainage field, so in part, or in the most part, now, if you started injecting water in that gravity drainage, you may ruin the gravity drainage next. So we want to find out where there is no gravity drainage where the shales are and not just the shales from the cores and the logs but also the shales from the production history. That's why we need some production history. It's rather obvious we're going to go, I mean, that the industry will start flooding the eastern part of the field now that we have confirmed that shale breaks are accurate. That's why we have to have history. Where in all the other stages are correct. If you have a small field and no good drive mechanism, you start injecting water and it doesn't matter where you put it in, you're not ruining anything. In this case, you have a chance of ruining a good mechanism by waterflooding so you want to be selective in where you put it.

BY: MR. GRIFFITHS

Since shale continuity is such an important factor, a group composed of ten geologists from five companies spent thousands

of man hours verifying and updating shale correlations and making predictions as to their continuity between wells and in undrilled areas in the field. This work has indicated that the shales are less continuous than previously predicted, which emphasizes the need to proceed with caution. Further improvement in the shale description will result from continued drilling and history matching the production performance of the field and wells with reservoir models. Also, the vast number of pressure buildups and the interference test data are providing insight into shale continuity and reservoir depletion mechanisms. A reservoir engineering study group from the Unit Owner companies has been working steadily to narrow the uncertainties related to this project. The group has identified seven potential waterflood areas in the field and has undertaken specific reservoir studies in all of the major areas. The key to verifying the benefits to be derived from waterflooding is the analysis of the production and test data that is constantly being collected. Highly sophisticated "state-of-the-art" reservoir models have been developed and we are now comparing the detailed performance history with the model predictions. By next year the owners expect to have the knowledge upon which to base initial waterflood decisions. To enable an early evaluation of the many reservoir and mechanical factors which can affect the success of a large scale waterflood, the Unit Owners have

implemented two pilot water injectivity tests in the Sadlerochit reservoir. One of the tests, located in the Western Operating Area near Gathering Center No. 3, was completed recently and the data that has been obtained is being analyzed. The other test, located in the Eastern Operating Area near Flow Station No. 1, is underway and will soon continue -- and will continue for about nine more months. The pilot tests have been designed to evaluate reservoir parameters such as injection pressures and injection capacity in the wells, the efficiency of water in displacing oil in the reservoir, aquifer properties, and the impact of water quality on injectivity. The mechanical factors under investigation include an evaluation of two artificial lift systems, potential corrosion, scaling and freezing problems, and general design parameters. In addition, a valuable benefit from the tests is an opportunity to gain operating experience with a North Slope waterflood. Although very costly, so far about $33 million, the tests are providing extremely worthwhile data. Soon after unitization, the owners formed a Waterflood Task Force. The Task Force, consisting of sixteen full-time engineers from several owner companies, was charged to accomplish the design studies previously mentioned and develop a conceptual design for a waterflood project. The normal sequence of events in the design and implementation of a waterflood is first to define the benefits to be derived from

the flood and then specify design parameters, such as flood locations, volumes, pressure, quality, etc., and then design a system to meet these requirements. Because of the time required to fabricate and construct a major facility such as this at Prudhoe Bay, we have carried out the facility design and the reservoir engineering studies concurrently. As a result, the design was developed to accommodate a range of potential flood volumes. As is the case with most projects of this magnitude, a wide range of alternative concepts was developed for practically every facility in the system. In July, 1978, we retained Bechtel Inc., an engineering contractor, to fully evaluate these alternatives. An average of fifty contractor personnel have been employed in the conceptual design studies. Early this summer, we developed a conceptual waterflood design which will accommodate the range of potential injection requirements, as I mentioned. The slide before you shows a layout of the waterflood system. The conceptual design envisions the Beaufort Sea as the water source. The seawater would be treated in a facility located near the end of the west dock (indisc). From there the low pressure lines would carry the treated water to two water injection plants, one located in the east area near Flow Station No. 1 and one in the west area near Gathering Center 1. From the plants, high pressure injection water would be transported to appropriate drill sites and

drill pads for injection. Although we still need to resolve several design questions during the next phase of the engineering, which incidentally is alrady underway, the project is mechanically feasible and environmentally sound. Prudhoe Bay owners recently submitted applications to the Corps of Engineers for major permits required to install waterflood facilities. Supporting these applications is a two-volume document entitled, Prudhoe Bay Unit Waterflood Project Overview, and I have copies of those here. Volume 1 is the engineering overview and it is a pretty complete description of the Prudhoe Bay conceptual design as it stands now. Volume 2 is an environmental overview that s prepared by a consultant, Woodward Clyde, and Mr. Chairman I'd like to leave copi s with you for the record.

BY: MR. ROGERS

May I ask, is that -- are you going to have to file a environmental impact statement in addition - in addition to that for waterflooding plant?

BY: MR. GRIFFITHS

We expect that an environmental impact statement will probably be required. Ah..the determining agency will be the Corps of Engineers .

BY: MR. ROGERS

And..ah..are -- do you have any problem with water injection in the winter up there?

BY: MR. GRIFFITHS

Some of those 18 studies that I've mentioned were addressed to that very question and we think -- well, we're quite certain that we can operate through the winter months.

BY: MR. ROGERS

Well, maybe you're going to get into this later, but I understand the North Slope Borough has an ordinance that could effect -- it effects a lot of the activities up there, is that going to effect the waterflooding operation do you think?

BY: MR. GRIFFITHS

We really don't know, that ordinance has not been finalized, to my knowledge.

BY: MR. NORGAARD

Certainly it is a concern to us. We are working with the borough and..ah..you know -- we intend to work with the borough in every way we can, but that is a very great concern to us that..ah..they -- they are moving forward on "CZM" ordinances and what is written right now would be very difficult to operate and work with, and we're optimistic that we will be able to work with them to come up with something that makes sense, but that's a great concern.

BY: MR. ROGERS

Am I hearing you say then that the ordinance could prohibit you from waterflooding?

BY: MR. NORGAARD

We will have to get the borough's concurrence on what we

propose to do, yes, as well as the Corps of Engineers, as well as the State of Alaska, as well as, I believe, the citizens of Alaska. I'm not sure that there's anybody's approval we don't need.

BY: MR. CHATTERTON

(Indisc - simultaneous speech) I told you that I would like an opportunity to ask a facetious question, but I guess it's been partially answered, so I'll rephrase it. Have you or do you plan to send a courtesy copy to the North Slope Borough, to the Coastal Zone Management..ah..group, also?

BY: MR. NORGAARD

We have met with just about all agencies that have any involvement and met with the borough at least twice before submitting the application to them. We've visited with -- explained what we were planning on doing and have gotten any suggestions that they have had at that point in time and we certainly would intend to follow to all these agencies with the permits, but it does have to go through the Corps of Engineers and then they become the lead agency and they do their thing. We are continually following and working with all agencies to see if we can't assist them whatever way we can and answer questions that they must have, certainly they will have some questions. Thank you for the question, Mr. Chatterton.

BY: MR. CHATTERTON

Thank you, Mr. Chairman. You're welcome.

BY: MR. NORGAARD

I was suppose to say that when I got a chance and I forgot.

BY: MR. GRIFFITHS

As we have pointed out before that the waterflood implementation schedule envisions a 1984 startup and this slide shows the events needed to get to startup in 1984. A major decision will be required on the part of the Unit Owners in mid-1980 in order to achieve a 1984 startup. To meet this objective, we must complete the preliminary engineering design and sufficiently resolve the reservoir uncertainties in order to verify the recovery benefits by that time. Also, I know that you can appreciate our need to have permits in hand prior to any major commitment of funds to the project. If the decision is to proceed with the waterflood, long lead-time equipment orders will be placed and the final design of the system will commence about mid-1980. Fabrication will begin in mid-1981. Sealifts then will occur in 1982 and 1983 and construction of the facilities on the North Slope would take place between 1982 and 1984.

BY: MR. MILES

Excuse me Dave, I guess I'm missing something in the time frame. I thought the water injection, natural water injection was going to begin in '81, that's when you got up to 100 thousand barrels of..ah..produced water.

BY: MR. GRIFFITHS

That's right.

BY: MR. MILES

Well how can -- if you got -- how can you do the engineering in '80

BY: MR. GRIFFITHS

I'm sorry, I failed to point that out that this is the schedule for the major waterflood, the source waterflood.

BY: MR. MILES

So those are really two independent operations, completely independent of each other.

BY: MR. GRIFFITHS

They're independent in that the time frame is different and the source of water is different. Eventually, of course, those two systems will have to be -- will have to come together, not physically, but from a injection sense and become part of one major waterflood system.

BY: MR. MILES

I see, but the produced water injection, or the source water injection doesn't depend on what happens from the produced water injection, when you pump the 100 thousand barrels back in.

BY: MR. SMEDLEY

Not at least in the first increment because the basic decisions will have been made for the first part of the source water system before the -- before you'll have that information.

BY: MR. NORGAARD

I think, we're tied in with what both Dr. vanPoollen and

Doscher indicated was that some of the information we can get through laboratory studies and with the injection programs we currently have, the two programs we have now that one could call the tests or one could call pilot, depending how you felt that day, and we are anticipating getting all the information required, to go ahead and make the decisions in 1980 from those two pieces, so we do not need this source water injection to make the decision in 1980.

BY: MR. MILES

Well, you -- okay, you don't need the information from the produced water injection to make the source water injection decision in 1980, is that correct?

BY: MR. NORGAARD

Yes.

BY: MR. MILES

I see, okay, thank you.

BY: MR. ROGERS

Could you tell me what you're expecting for a construction work force up north.

BY: MR. SMEDLEY

Our current estimate is about 1600.

BY: MR. ROGERS

And a maintenance work force after you've completed construction.

BY: MR. SMEDLEY

Oh, in the order of 100 people to operate a system depending on how large the system turns out to be.

BY: MR. GRIFFITHS

I'm sure you will recognize most of the areas constituting the project schedule are inter-related and delay in finalizing one segment could impact the overall schedule. I would like to briefly discuss each of these major segments and identify those areas that potentially could delay the implementation of the waterflood. The reservoir studies, of course we have discussed at great length, I don't think I need to expand on those, except to say we do have a high degree of confidence that the reservoir studies will develop the necessary design parameters and recovery benefits on time. The major permit applications have recently been submitted, and consequently, it will be several months before a firm assessment of the permit timing can be made. Since the potential exists for considerable slippage in this area, permitting could become a critical factor in achieving a 1984 startup. The preliminary engineering design phase is an in-depth review of the system that has been developed in the conceptual design. At the completion of this phase, all major equipment for a system to handle a finite volume of water at specified locations and pressures will be identified. This is a major engineering effort. Final design is the

phase in which equipment and piping layouts, valve and vessel design, control system layouts, and construction drawings are prepared. Again, for a project of this magnitude, this will be a massive effort involving about 1000 owner company and contractor engineering personnel. The long lead items include structural steel, turbine-driven pumps, water treatment equipment, and other specialized items associated with the flood. We have forecasted delivery times based on our previous experience with such equipment and forecasts of market conditions and their availability. Unforeseen changes in availability of these items could cause delayed deliveries and if these deliveries are severe, the delays are severe, it could delay a sealift. In the fabrication stage, the equipment previously mentioned is assembled in modules for sealift to Prudhoe Bay. The principle variables affecting this schedule are material deliveries and manpower availability. The critical factor here is that minor slippage could cause a delay of one year in the sealift. Sealifts are the vital link between the North Slope and the Lower 48. Due to the size of the modules no other transportation system is feasible. The critical factors affecting the success of a sealift are the ice conditions in the Beaufort Sea and the ability to unload barges once they arrive at Prudhoe Bay. The ice factor is beyond our control, of course, but we have been able to achieve at

least a partially successful sealift even under the worst conditions experienced during the past five years. Our planning calls for the waterflood equipment to be sealifted at the same time the other major facilities that Larry mentioned, are programmed for the Prudhoe Bay Field. The total forecasted requirements will tax the existing dock facilities, and our ability to achieve that goal would be highly questionable if it were not for the West Dock and causeway. With this facility, we can develop the offloading capacity. The North Slope construction schedule is based on several years of experience. The primary factor that would affect this schedule is an unforeseen lack of construction manpower. The commissioning and startup of the waterflood system will, in some respects, be a unique experience and as such, it could encounter minor delays. By 1984, however, we will have had a produced water injection system in operation for three years which, along with the injectivity tests, will develop valuable operating experience. In general, we feel we have a realistic implementation schedule and are confident it can be achieved. On the other hand, we feel there is very little chance that the schedule can be accelerated. The one area that will have the most impact on the schedule is the timely receipt of the necessary permits. The permit schedule carries the greatest chance of -- for slippage and could easily delay the project a year or more.

BY: MR. ROGERS

Yea, what State permits are required?

BY: MR. GRIFFITHS

There's a..ah..a permit required that you operate from the Oil and Gas Commission, there are permits that are required from the Dept. of Environmental Conservation, there are permits required from..ah.. the land department I don't recall -- Fish and Game (indisc) land use permits..ah.. affecting gravel and what have you and the Fish and Game Department, that's correct.

BY: MR. ROGERS

Do you think it would be -- would be helpful in this -- in the critical permiting area if the State were to appoint a permit coordinator or some -- some sort -- equivalent to the pipeline coordinator that we've got on board.

BY: MR. NORGAARD

Are you speaking for just waterflood or total?

BY: MR. ROGERS

Well, for the waterflood.

BY: MR. NORGAARD

Well, as you understood there's a lot of other things that are very critical too, besides just the waterflood, we got a lot of other facilities that will be going and they're equally critical, because almost of them require permits of some kind all the way through. Really, our permit dealings

with the State during the X period of time have been -- we've been very satisfied. We are, I believe, working very well together. Our greatest concern that we have at this point in time, is the multitude of different -- bodies that we deal with, the North Slope Borough, the Corps of Engineers and the State, and being able to coordinate those things together and seeing that one doesn't have objective A and one doesn't have objective B and they conflict. Who's going to resolve that conflict. That's our biggest concern right now, it isn't so much dealing with the State or dealing with the Corps.

BY: MR. ROGERS

Do the three governments have any -- any kind of..ah..group -- the same way the operators have a group planning for this-- do the three governments...

BY: MR. NORGAARD

Not at this time, the Corps has indicated a desire and willingness to work with the State, so that their systems are compatible in -- would simplify the process. I'm really not familiar enough with the borough's intentions to speak to that. Somebody here may be, I'm not. That's a new phase that we're just getting into -- you know -- and that's going to be one that we'll have to crawl before we can walk, I guess.

BY: MR. ROGERS

Could you keep the committee posted on, particularly the

State's efforts and if there are any problems along that.

BY: MR. NORGAARD

We would love too, thank you.

BY: MR. ROGERS

On manpower requirements, are there any specialized forms of training required that we might want to -- that the State might want to be pushing in the next couple of years to make sure we had the right kind of manpower available for you.

BY: MR. GRIFFITHS

No, the craft manpower that will be required to install the waterflood will be the same disciplines that have been available in the past to install the existing facilities and the same people are going to be....

BY: MR. ROGERS

The same ones are primarily non-residents which is why I was asking the question. Is it primarily plumbers and steamfitters dependent work that would....

BY: MR. GRIFFITHS

I think it crosses a whole range of crafts and manpower, electricians, plumbers, welders, pipelayers, just about every -- every profession is up there.

BY: MR. NORGAARD

I don't believe that you'll single anyone out, you see, that's the one you concentrate on.

BY: MR. ROGERS

Do you know well enough which ones you're going to need so

we can try to assist at all in making them available.

BY: MR. GRIFFITHS

Our studies, as far as the waterflood are concerned, have not gone into that detail.

BY: MR. NORGAARD

Let us worry that a bit because it's a broader question than waterflood question. We do have lots of other facilities going. And, we have looked at what the requirements will be on the slope (indisc.), and we just have to look at that and talk to our construction people.

BY: MR. ROGERS

'Cause you're going to be going at the same time as some gas-line construction, perhaps it's quite possible that a lot of these things will be going on concurrently and that could create some -- a demand that we couldn't fill with residents unless we knew about it in the next year or so, so we could gear up some training programs.

BY: MR. NORGAARD

We appreciate the desire.

BY: MR. ROGERS

If there is any way that you can let us know during the next legislative session, I think it would be rather helpful.

BY: MR. NORGAARD

We will be happy to work with that .

BY: MR. MILES

Dave, you indicated a passle full of permits that you have to get from Fish and Game, the Land Use Planning and Environmental Conservation and who knows, did you say in your presentation what the status of those, have those all been applied for, have they been filled out or what -- for the waterflooding project?

BY: MR. GRIFFITHS

So far we have made applications the Corps of Engineers for about six or seven permits.

BY: MR. MILES

You haven't done any State applications and permits.

BY: MR. GRIFFITHS

We have not applied for State permits for the waterflood as yet. That's going to be one of the next steps.

BY: MR. MILES

Okay, if this is one of the most significant problems and it seems like everybody's been saying, all along, you planned to go into this full scale waterflooding project, why didn't you start sooner?

BY: MR. GRIFFITHS

Well, in order to submit a permit application we had to have a conceptual design. The Corps of Engineers or whoever will permit a specific system, they won't just permit waterflooding -- you know -- across the board. We had to

develop a conceptual design and document it and also to prepare an environmental overview for that system, prior to submitting permits. Earlier this summer, we did complete that conceptual design and then moved right ahead with the documentation of it and the environmental aspect of it. As soon as those were completed the permits went in and we anticipate the longest lead permit will be from the Corps of Engineers.

BY: MR. MILES

I see. You couldn't simultaneously apply for all of these, is that right?

BY: MR. GRIFFITHS

No sir.

BY: MR. MILES

You got to -- do you have to get something back now from the Corps of Engineers?

BY: MR. GRIFFITHS

We have to get an okay, our first look at it, yea, it looks like its a hell of a deal.

BY: MR. MILES

Do they -- say something like that before you can apply to the Dept. of Environmental and Conservation. I just don't know what the -- you know -- what the....

BY: MR. GRIFFITHS

No, we do not have to get something back fro the Corps of Engineers before we make..ah..subsequent applications.

Matter of fact, we have other applications in the process right now, that have not been submitted but they're being prepared. Ah..the first act from the Corps of Engineers, first official act, will be whether or not the Corps of Engineers declares this a significant federal action.

BY: MR. MILES

Are they slower than the State is that why you went there first?

BY: MR. NORGAARD

Dave let me see if I -- let me see if I can answer your question. We obviously, as everybody, there's only so many things you can do at one time and so we take the most critical element first and the most critical element was the permit from the Corps of Engineers and we will go ahead and follow that -- you know -- as quickly as we can get the data together in the form that's desired and required and move forward on the permits. But, we don't see any of the other ones as being the critical length. The one that's in is the critical length. We may have guessed wrong, we don't think we have. We see that as being the most critical and we got that in as fast as we could. Now, we'll take the same data that we had in that application and put it in a different format so it satisfies the other permit requirements. But, we have visited with all the people already, got their input so we know what their concerns and desires and requiremen

are and, therefore, in that context we have got a jump on the game, if you will, and that was it -- we were able then to pick the most critical and move forward on it.

MR. CHATTERTON

Thank you, Mr. Chairman. Dave, you made sort of an innocuous statement about the westside dock and causeway. I've been told that the Corps of Engineers' permit, and I don't know whether it was issued through the unit or to ARCO, had a requirement that they remove at a certain time, and I've further been told that there are those that are pressuring the Corps to have you meet that requirement. Now, apparently this west dock and causeway is an integral part of your waterflooding, -- have I been told right is the first question and where's that issue stand now?

BY: MR. GRIFFITHS

I don't know really if somebody is being pressured for us to take the dock out. I think the initial permit did not stipulate we would have to take the dock out, it stipulated we would have to do environmental studies which we have done each year to assess the impact of the dock being there and I suppose we would be subject to take -- having to take the dock out if there was an environmental impact shown. So far, there has not been any environmental impact shown.

BY: MR. CHATTERTON

As far as you're concerned.

BY: MR. NORGAARD

The permit did -- you'd have the stipulation that we could be required to taking the dock out at a point in time. It did not say that we had to, but it has the stipulation that we can be required.

BY: MR. CHATTERTON

Thank you, thank you, Mr. Chairman.

BY: MR. MILES

(indisc - simultaneous speech) Mr. Griffiths did you conclude your statement?

BY: MR. GRIFFITHS

I just have one brief summary, Mr. Chairman.

BY: MR. MILES

I thought you had concluded. Joe do you want to go now or...

BY: MR. McKINNON

Well, I'm not sure -- just one question. One of the things you're doing to increase recovery is to double up spacing of wells to..ah..150 acres and that increases it by 4% or 5%. What would increasing it to 80 acres make?

BY: MR. SMEDLEY

That's as we indicated in the May, '77 testimony. The way you go about developing is you drill and we were then drilling on 320 acres spacing, and we've since been drilling on 160 acres spacing. We will continue to look at that and as we drill and see performance of these wells -- you know --

reservoir, to drill wells on 80 acres spacing, and, if so, we would go to the Oil and Gas Conservation Commission and ask for permission to do so. Right now, the Pool Rules specify 160 acre spacing, so we would have to get permission to drill on denser spacing.

BY: MR. NORGAARD

ARCO did testify at the May, '77 hearing that by drilling, and I forget how many 80 acre wells, but there were quite a number, that recovery would be increased by 1%, either 1 or 1.2. Chat could check me out, but it's in that range. The point is that you can increase oil recovery, obviously, by adding wells, but it's a diminishing return to go from 320 to 160 got 4%, to go from 160 to 80, in certain areas, got 1%. Ah.. so, and I forget who it was yesterday suggested that you could mine the Prudhoe Bay, I guess it was Hoyle, but you could mine Prudhoe Bay and 100%. And that's -- the closer you're making wells, that's the closer you are to mining the reservoir.

BY: MR. CHATTERTON

May I make a statement for the record that with this discussion that we've had and seeing as how my name was mentioned, I have a distinct conflict of interest and I'd like that known. (Laughter)

BY: MR. MILES

Go ahead, Mr. Griffiths, if you'd like to conclude.

BY: MR. GRIFFITHS

In summary, the Prudhoe Bay Owners have proceeded in an aggressive and orderly manner to verify the feasibility of a waterflood in the Sadlerochit Reservoir. This course follows very closely the program outlined in the Unit Owners' presentations before the Oil and Gas Conservation Committee during the hearings in May, 1977. Reservoir studies and design studies have progressed concurrently. Injectivity tests have been designed and implemented, and analysis is progressing with the production date -- production history and test data obtained to date. As a result of many years of reservoir studies and the analysis of field production, we feel we are developing an excellent understanding of the Prudhoe Bay reservoir and its future performance. We intend to continue our extensive efforts to build on this foundation. During the past two years alone, the Prudhoe Bay Unit Owners have invested over 40 million dollars in engineering studies and special tests designed to reduce the risks associated with a source waterflood. The Waterflood Task Force has developed a conceptual design based on a Beaufort Sea water source and the Task Force is proceeding into the next phase of engineering. Permit applications have been submitted to the Corps of Engineers. Permitting could become the critical factor in meeting a 1984 startup of the project. The Unit Owners plan to be in a position to make the decision to

proceed with a source waterflood project by mid-1980 if the permits are in hand and the project is determined to be economically viable. Mr. Chairman, that concludes my testimony. I think Mr. Norgaard has some concluding remarks .

BY: MR. PARR

I have one question and you probably mentioned this and I missed it. Have your tests indicated that this Beaufort Sea water is suitable for the purpose or is it -- are you going to have to build a conditioning plant of some sort or what?

BY: MR. GRIFFITHS

Yes, we will have to build a treating plant. Now the Beaufort Sea water, based on the tests that we have run so far and those tests started back in 1976, indicates that the Beaufort Sea is a very good quality water, but still it will require some treatment and heating and that facility is the one that will be located out at the end of the west dock.

BY: MR. PARR

Thank you.

BY: MR. MILES

Are there other questions? Mr. Norgaard, would you conclude?

BY: MR. NORGAARD

It's been long and I'm going to make a very short concluding statement. Maybe, that will be unique for me. First off, I think that Prudhoe is unique in one respect and it's come

out repeatedly and that is the money, technical expertise and manpower that have been dedicated to that field to learn as much as we can and to manage it as properly as we can for all parties concerned. I think it's unique in the annals of oil fields and considering the reservoir we're dealing with, it's appropriate, and I think the oil companies will continue to treat it as such. Secondly, the plan is a sound plan, and we believe it should be followed. We believe we said that very clearly. We see it actually maximizing the amount of oil and gas to be recovered from the Prudhoe Bay Field and I think oil and gas is important. I know Dr. Doscher did not feel that 1.5 trillion feet of gas was significant. That equates to over 200 million barrels of oil, so I guess I feel it is equivalent. And, in my opinion, it definitely is something that will not be seen. When you burn it, you burn it and that's that. Ah..thirdly, the plan, I believe again, is prudent for both the owner companies and the State of Alask and, in this regard, I believe our interests are essentially identical. And the reason for that is the reservoir is a kind of reservoir where the decisions are not borderline decisions. They are broad, big decisions in the different economics that exist between us, which will always exist between us; it's not a critical element. And, lastly, we have worked with this Oil and Gas Conservation Commission in the past, we certainly intend to work with them fully in the future

and..ah..we expect to share our ideas and thoughts and our information with them as frequently and as openly as they desire and that's the end of my -- and we thank you again for the opportunity to be here today and, hopefully, we've shed some light on what we're doing and what it means to you and to the State of Alaska. Thank you.

BY: MR. MILES

So, great gentlemen..ah..thank you very, very much -- it's been thoroughly enlightening to me and I think to other members of the Committee. We know you have gone well out of your way to come up here and put your presentation together, and it has been enlightening and most appreciated. Also, I'd like to thank you, Ken, for what you did in organizing the effort. It's most appreciated. It's now 6:15. I think we'll back up our voluntary evening session at 7:15 and give everybody at least the time to have one martini at dinner.

LAW OFFICES
BIRCH, HORTON, BITTNER AND MONROE

733 W. FOURTH AVE., SUITE 206
ANCHORAGE, ALASKA 99501
(907) 279-9403
TELEX 25-358

1200 AIRPORT HEIGHTS DRIVE
ANCHORAGE, ALASKA 99504
(907) 279-9501

4400 JENIFER ST., N. W. - SUITE 300
WASHINGTON, D. C. 20015
(202) 244-4250
TELEX 9-89-2591

751 OLD RICHARDSON HWY., SUITE 340
FAIRBANKS, ALASKA 99707
(907) 452-1666

130 SEWARD STREET, SUITE 314
JUNEAU, ALASKA 99801
(907) 586-2890

MEMORANDUM

To: Joint Interim Natural Gas Pipeline Financing Committee

Date: July 27, 1979

THE ALASKA NATURAL GAS PIPELINE: CURRENT PROSPECTS FOR FEDERAL ASSISTANCE

This report is in response to the Committee's request that we examine the issues involved in possible federal financial support for or participation in the Alaska Natural Gas Pipeline project. The specific areas of inquiry suggested by the Committee include:

1. What would be the most likely forms of federal participation?

2. What is the overall likelihood of federal participation?

3. If federal participation occurs, when is it likely to come about?

4. What events must occur in order to make federal participation a reality?

5. What steps could the State of Alaska take in order to convince the federal government that such financial support or participation is necessary?

6. In the event the State chooses to actively solicit federal participation in the project, what areas of the federal government and what methods of approach would be most likely to achieve favorable results?

The remainder of this memorandum discusses these questions. By way of preliminary comment, it should be noted that since the Committee requested the analysis of these points (at its meeting of June 4, 1979), there has been a significant upheaval with

AGO 532449

regard to the domestic energy policy situation and with regard to international energy prices. The result of the major OPEC price increase of July 1, President Carter's domestic policy summit at Camp David, and the subsequent attempt by the President to initiate major personnel and policy changes within his Administration, have all combined to make this report somewhat more speculative than might otherwise be the case. Consequently, where these major events have influenced our analysis, we have so noted. We have also added analyses of President Carter's latest energy proposals where appropriate.

Possible Forms of Federal Financial Participation

As evidenced by the President's recent proposals on synthetic fuels, the range of possible federal support for the proposed Northwest Alaska Natural Gas Pipeline is great. The material provided to Congress describing the President's proposal to establish an Energy Security Corporation (to promote synthetic fuels and unconventional natural gas supplies) contained the following financial authorities which would be provided to the Corporation:

1. Direct loans to companies that produce or manufacture synthetic fuels or unconventional natural gas supplies.

2. Loan guarantees for such projects.

3. Authority to guarantee prices of synthetic fuels or unconventional natural gas supplies.

4. Authority to guarantee federal government purchases of such materials.

5. Direct government ownership of a maximum of three synthetic fuels projects.

Specifically excluded, however, is authority to make equity investments, enter into joint ventures, engage in lease or lease-backing arrangements, or make grants.

Based on our conversations with Congressional staff and Executive Branch officials, we believe that provision of loan guarantees for at least a portion of the Alaska Natural Gas project is the most likely alternative in the event the federal government decides that financial assistance for the project is

appropriate. Based on our conversations, we believe guarantees would be seen as a distinctly preferable alternative to direct government loans because guarantees involve only a contingent liability for the federal government and involve the smallest risk of involving actual federal cash outlays. Because the government has yet to change its position that the project can and will be privately financed, the exact nature of any loan guarantee program is necessarily speculative. However, we again believe the general parameters of the loan guarantees proposed in the President's latest energy program may be illustrative:

1. No guarantee shall be extended unless the chairman of the Energy Security Corporation finds that credit is otherwise unavailable to carry out the project on reasonable terms and conditions and that adequate provision is made for servicing the loans on reasonable terms.

2. The guarantee shall not exceed 75% of the project cost, as estimated at the time the guarantee is issued. The guarantee amount may be increased, at the discretion of the chairman to cover 60% of that portion of the actual total project's costs which exceed the project costs of such facilities as estimated at the time the guarantee is first issued.

3. The chairman will seek to the maximum extent practicable to grant guarantees on a competitive basis.

4. The chairman shall charge and collect fees for guarantees in amounts sufficient, in his judgment, to cover applicable administrative costs and probable losses on guaranteed obligations, but in any event not to exceed one percent per annum of the outstanding indebtedness covered by such guarantees. Such fees may, however, be waived with respect to specific projects.

5. The loan to be guaranteed shall be secured by such collateral and additional security as may be reasonably required by the chairman for the protection of the corporation.

6. The chairman may provide for the payment to holders of the obligation guaranteed for and on behalf of the borrower, the principal and interest which become due if the chairman finds that:

a. the borrower is unable to meet such payments;

b. it is in the interest of the corporation to permit the borrower to continue to pursue the purposes of such project;

c. the probable net benefits to the corporation in paying such principal and interest will be greater than that which will result in the event of default; and

d. that the borrower agrees to reimburse the corporation for such payment on terms and conditions, including interest, which are satisfactory to the chairman.

7. With respect to any obligation which is guaranteed, the interest paid and received by the purchaser (excepting tax-exempt entities) shall be included in the gross income of the purchaser for the purpose of Chapter 1 of the Internal Revenue Code of 1954, as amended.

8. The chairman shall consult with the Secretary of the Treasury as to the timing, rate and terms of loans or loan guarantees.

A second and much more remote possibility would involve provision of purchase guarantees for some or all of North Slope natural gas production. Essentially, such an approach would attempt to address the marketability problem for Alaska natural gas: i.e., that even with rolled-in pricing the delivered price of this gas may be too high to make it economically attractive. Under a purchase guarantee system, the government could conceivably contract to purchase North Slope natural gas at the higher "uneconomic" rate and then resell such gas at a lower price (the BTU-equivalent price for No. 2 home heating oil, for example), absorbing the difference as a subsidy loss to the Treasury. As we stated previously, however, we think such an alternative is extremely unlikely. Not only is this alternative more complex than provision of loan guarantees (hence, more difficult to shepherd through Congress), it also exposes the federal Treasury to a continuous drain. In the event that marketability as opposed to assumption of risk becomes a problem for the project, we believe a more likely federal approach might be a combination of loan guarantees and more stringent rate of return controls, both in terms of pipeline rates and, possibly, wellhead prices.

What is the probability of federal participation?

Based on our conversations with both Congressional and Executive Branch sources, we believe that the eventual provision of federal financial assistance to the Northwest Alaska Natural Gas pipeline project has become quite likely. As evidenced by recent statements by the President, a renewed and very strong commitment to a major national energy program is underway. The proposed Northwest pipeline represents the energy equivalent of

700,000 barrels per day of oil imports -- 28% of the proposed 2.5 million barrels per day of energy production called for from synthetic fuels and unconventional gas sources by 1990 in the President's program. Unlike synthetic fuels and unconventional gas sources, the North Slope reserves are known and can be produced and brought to market utilizing existing -- if expensive -- technology. Thus, in the event that the project fails to finance privately, as now seems likely based on numerous expressions from the financial and energy community, federal financial support would seem to be very likely in that federal assistance to the project would result in the easiest, least expensive (to the federal government), earliest, largest, and -- most importantly -- surest single increment to the nation's energy supply of any of the options available to the federal government.

The likelihood of federal support has been bolstered recently by the energy speeches delivered by Vice President Mondale and then President Carter (in Kanasas City) during the Camp David and post-Camp David periods. While neither confronted the possibility of any type of government subsidy, both indicated that the Alaska Gas Pipeline is considered part of the fabric of our energy planning for the mid-1980's. Neither referred to the gasline as a prospect, but rather as a fait accompli. Specifically, the Carter quote was: "one major project will be the new pipeline to be built from Alaska through Canada to bring natural gas to the lower 48 states. By 1985 Alaskan and Canadian natural gas can displace almost 700,000 barrels of imported oil per day." Moreover, it is noteworthy that the Alaska gasline is the only new energy source that can produce a consequential amount of oil-equivalent by the middle of the next decade, rather than at decade-end.

Under what circumstances is federal participation likely to occur?

Despite this summer's gasoline crisis which has whipped the Congress into an at least temporary frenzy of enthusiasm for new approaches to solve the nation's energy problems, we have found no evidence at the federal level of a change in policy toward financing the gas pipeline. Despite this summer's disruption of the gasoline markets and despite the dozens of bills introduced in the Congress calling for major federal assistance to synthetic fuels projects, the Congress continues to view the Alaska Natural Gas project as a separate entity that must be privately financed.

On the whole, those whom we contacted in Congress demonstrated a low level of knowledge regarding the financing difficulties of the project and expressed the view that since Congress had already acted in approving the Alaska Natural Gas Transportation Act, as well as the President's decision selecting the Northwest project,

that the subject was essentially closed. Of the offices contacted, the clearest response was provided by Senator Henry Jackson, Chairman of the Energy & Natural Resources Committee. According to Jackson's staff, his position with respect to federal assistance for the project has not changed: "The till is closed." In the judgment of Jackson's staff, this position will not change unless and until Northwest concedes that it cannot finance the line privately (as promised to Congress) and either directly or via the Administration requests federal assistance. Jackson's staff predicted that such a request could open the entire project to an intensive Congressional and federal review and indicated that it might prove very difficult given the record to push such federal support through the Congress.

Despite the apparent analogy between the Alaska Gas Pipeline and the massive federal support program for synthetic fuels now being considered, it appears that the pipeline project is unlikely to be a recipient of federal guarantees or support as an "add-on" to any legislation currently in Congress. Congressional feeling on this is illustrated by the results of contacts with Senator Lloyd Bentsen's office. Bentsen recently introduced the Energy Mobilization Act of 1979 (S. 1516). Title IV of this Act would establish an expedited procedure by which major natural gas pipelines would be automatically considered "significant energy projects" and thus, subject to accellerated FERC review processes. Federal financial assistance for such major pipelines in the form of loan guarantees would also be available. However, the bill explicitly limits both the expedited review procedures and federal financial assistance to those pipelines located in the Lower 48 United States.

According to Bentsen's office, the Alaska Gas Pipeline was specifically and intentionally excluded from Title IV. According to the staff, this was done because, in their view, the question of providing federal guarantees to natural gas pipelines was sufficiently controversial without adding Alaska. They stated that any legislation dealing with Alaska automatically becomes "controversial" and attacts great attention and opposition from environmental groups and other lobbying organizations. In their view, if Alaska had been included in the provision, the chances for passage would have been significantly decreased. According to his staff, Bentsen believes that any action providing loan guarantees for a natural gas pipeline in Alaska must be considered as a separate proposal that stands or falls on its own merits, and that attempts to "fold-in" such assistance as a part of any of the major energy proposals now being considered in Congress will, in all likelihood, fail.

Outside of Congress, the public position with respect to federal assistance for the project remains unequivocally negative.

John Adger, Director of the Alaska Gas Project Office of the Federal Energy Regulatory Commission adamantly denied the existence of even a possibility of federal assistance. He indicated that the gas pipeline project will be privately financed and that any federal involvement would be limited to heavy Presidential pressure on the oil companies to participate in the debt financing. He emphasized that there has been no indication from the President in his recent energy speeches or proposals that federal participation is being considered. Similarly, he pointed out that there has been no such proposal contained in Congressional Energy Mobilization Board-type legislation.

Despite the political turmoil of the last few weeks, we spoke with several senior officials in the Department of Energy. While they indicated to us that the "regular" policy process was in some disarray because of the Cabinet reshuffle and that communications with the White House were not the best, the federal policy with respect to providing financial assistance had not been changed. Hence, if any policy initiative to change federal financing policy is underway, it must be occurring at the White House. While we cannot state categorically that such an initiative is not being considered, we have found no evidence of it.

Based on our conversations with federal officials, we concur with the estimate provided by Senator Jackson's staff: namely, that far and away the most important prerequisite for getting the federal government moving forward on a program of providing federal guarantees or other financial assistance to the project must be a decision by the management of the Alaska Gas Pipeline project that the private financing approach cannot work. If and when project management makes such a decision, the project in its current form can officially be laid to rest, a crisis atmosphere created, and alternative proposals formally considered. Given the fact that the federal government, from the President through the Congress, has endorsed and supported the concept of private financing, we believe it is extremely unlikely that an initiative in favor of federal support will be forthcoming from either the Executive Branch or the Congress until the private sector sponsors concede that the initial formulation of private financing is no longer a workable solution.

When might Northwest call for federal assistance?

Northwest continues to pursue a course that pays at least lip service to private financing. We must presume that Northwest management is privy to at least as much information regarding private financing prospects for the project as are we and the Committee, and therefore, that they are fully aware of the deep and increasing difficulties the project faces in achieving

private financing. Consequently, the question must be considered: Why, when private financing appears to be a small and diminishing hope, has not the company changed its position with respect to federal assistance?

In our judgment, there are two plausable reasons for this:

1. As Northwest is aware of its probable difficulties with private financing, it must also be aware that requesting federal assistance will create major political problems for the project and for the existing project management. Senator Jackson, a key figure in any federal financing assistance scheme, has made no secret of his continuing reliance on White House and corporate protestations that private financing is a viable alternative. As his staff indicated, were Northwest to return to the Congress asking for federal assistance, it would be "a whole new ballgame". Consequently, we believe one major motivating factor for Northwest's not throwing in the towel on the private financing approach at this time is the fact that they must appear to have foreclosed every reasonable alternative to federal financial assistance before they return to the Congress. Under any set of assumptions, it is likely that some in Congress will accuse the company of having falsely represented the possibility of private financing in order to obtain the North Slope pipeline franchise, with the intent of seeking federal guarantees when their initial proposal failed. Thus, if Northwest returns to Congress asking for major federal assistance prior to having completed virtually all attempts to gain favorable regulatory approvals from FERC and without attempting to formally obtain the necessary financial backing, it seems likely that they will run grave political risks. These risks could, in the event Congress felt they had been taken advantage of, even result in the loss of Northwest's franchise -- an outcome which the company surely wishes to avoid. In a somewhat related vein, Northwest achieves some advantages by pursuing its current regulatory course in the most aggressive manner possible, even with the knowledge that private financing is likely to fail. Specifically, if Congress "federalizes" the project, the possibility exists that Federal Energy Regulatory Commission rulemaking authority over the project might be limited or suspended. Consequently, the existing public record with respect to rates of return and tariff issues might be incorporated, at least in part, in any Congressional action taken on the project. Hence, it might very well redound to Northwest's advantage to achieve the most favorable regulatory treatment possible in the current proceedings with a view toward preserving such regulatory decisions in future Congressional deliberations on federal assistance.

2. Since the initial FERC rulemaking proceedings with regard to the incentive rate of return question were initiated last year,

Northwest has adopted an unyielding posture. Virtually every document submitted by Northwest to the Commission has indicated that the project will fail if the Commission does not adopt regulatory approvals substantially in keeping with those suggested by the partnership. This trend has been continued with Northwest's petition for reconsideration of Order No. 31 (the incentive rate of return and tariff order). In our view, this represents an effort by Northwest not only to get the most favorable decisions on the record prior to any consideration of federal assistance, but also an effort to establish a public record which makes clear that any failure to finance privately has not been due to shortcomings of the project sponsors. Rather, we believe that every effort will be made to place the blame for project failure, in the event that it occurs, upon the federal regulatory process, thus minimizing potential criticism of project management. Given recent statements by the President regarding his intention to bring increased pressure to bear upon the oil companies to provide financial assistance to the project, it is also possible that their "intransigence" may be portrayed as an additional reason that the project failed to finance in the private sector. It is also not difficult to see how the State of Alaska might easily be included with the oil companies in the event that project failure degenerates into a round of finger-pointing.

Based on the foregoing discussion, it seems that the timing of any Northwest decision to call for federal assistance will be heavily influenced by both the speed and content of actions by the Federal Energy Regulatory Commission with respect to the issues before it. As noted, the Commission is now considering Northwest's petition for reconsideration of Order No. 31 which is the regulatory "centerpiece" of the project. In the event FERC rejects Northwest's petition, the opportunity for a major change in policy for the company could occur relatively soon. In the event that the Commission accepts the petition and a further round of negotiation between FERC and the sponsors occurs, the final decision could be delayed until next year. In any event, based on our discussions with Congressional staff, we believe it is extremely doubtful that the Congress could pass federal assistance legislation prior to the spring of 1980, considering the current Congressional agenda and the fact that we believe any such legislation will be the subject of at least moderately extensive hearings and debate. A further complicating factor is the fact that any 1980 Congressional consideration of federal guarantees to the project coincides with both a Congressional and Presidential election year. While it is not possible to make any precise prediction regarding the effects of election year politics on the decisionmaking process, it is safe to say that this factor complicates the situation and in Washington, complications almost

always translate into delay. Thus, we believe the spring of 1980 is the earliest possible date for provision of federal financial assistance to the project and that such assistance is more likely to be seriously considered in 1981.

What steps might the State take in support of federal financing?

After having observed the great political inertia which exists with respect to this issue, we doubt that a direct lobbying campaign by the State of Alaska will have much effect on the speed with which Congress and/or the Executive Branch changes its current posture on federal financing. Our conclusion is based on the fact that the current "bind" facing the project is largely political rather than substantive. In short, we do not believe that provision of "better information" to Congress or the Executive Branch is a critical factor in speeding the process.

We do believe, however, that there are several steps the State can take which will at least minimize whatever delay is inherent in the process and which may assist in protecting the State's interest if and when Congressional consideration of federal guarantees is initiated. These steps include:

1. A concerted and coordinated effort, both by the Legislature and the State Administration, to provide a current information flow on positive State actions taken with respect to the project. This would include regulatory, environmental and right-of-way actions, even of a minor nature. This process would help establish a public record with Congress and senior Energy officials that evidences the State's good intentions toward the project. Such a campaign consisting, for example, of monthly mailings to the Congress and senior Energy officials could incrementally create an impression of the positive nature of the State's attitude toward the pipeline project. Such a perception in Washington could be of great value to the State in the event Congress engages in a minor league "witch hunt" in order to assign blame for project failure.

2. As we indicated above, we do not believe direct lobbying in Washington would be of signficant benefit in speeding federal assistance for the project. It is not so clear, however, that private and frank discussions with senior Northwest officials regarding the need to request federal assistance from Congress in order to speed the project might not be productive. To the extent that such discussions may have already occurred, at least informally, it is logical that they would have involved senior members of the State Administration.

3. To the extent that Northwest may in the end attempt to lay the blame for the failure of private financing at the door of other parties, it may become increasingly important for the State to take some steps to protect itself by positive action on its own program of financial assistance. We believe general approaches such as those suggested by Arlon Tussing in his memorandum to Senator Mike Colletta and Representative Bill Miles of May 14, 1979 should be carefully considered. In our view, even the most minimal and contingent sort of commitment to the project could have important value to the State as the question of financial assistance is considered in Washington. The very real possibility must be considered that Congress may demand a "pound of flesh" in return for federal financing -- and it is possible that the pound of flesh would be exacted at the wellhead and/or in the pipeline rates of return to operating companies. If the State is on the record as having taken at least minimal steps across the board to support the project, it will be able to come to the proceedings in Washington with clean hands; alternatively, and absent evidence of such State action, the Congressional response could be to take action to penalize those parties, including the State, which it perceives as having failed to adequately support the project. Such an approach would almost certainly be guised as a "proconsumer" step (i.e., lowering or taxing the wellhead value or reducing pipeline tariffs in some fashion) and would undoubtedly be termed an appropriate price to exact in return for guarantees provided by the nation's taxpayers. The current proposal to impose an excess profits tax on Alaska oil, despite the fact that this oil only recently reached previous federal price ceilings, is illustrative of the ability of Congress to impose new and contradictory conditions on energy production, if it wishes.

We recognize the great difficulty that the State and the Legislature have in attempting to move forward on this project, given the great confusion and disarray that currently exists in Washington. Nonetheless, we believe taking at least minimal steps and publicizing those positive actions to the Congress and the federal bureaucracy could provide the State with some protection against possible punitive Congressional action at the time federal guarantees are considered. Such a program will improve, although by no means guarantee, the prospects for equitable treatment of the State of Alaska in future Washington consideration of federal loan guarantees and project restructuring.

Joseph M. Chomski, Esq.

Richard G. Haggart

Lisa B. Nelson

AGO 532459

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN
REP. BILL MILES, CO-CHAIRMAN
SEN. FRANK FERGUSON
REP. C.V. CHATTERTON
SEN. BILL SUMNER
REP. TERRY GARDINER
REP. JOE HAYES
REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

August 2, 1979

REPORT ON INFORMAL MEETING OF THE JOINT GAS PIPELINE COMMITTEE
By Mary Halloran, Research Analyst

On July 31, 1979, newly appointed Federal Inspector John Rhett met with members of the Joint Gas Pipeline Committee in Anchorage. The discussion covered several items:

STATE HELP FOR THE PROJECT -- Rhett stressed that one major thing the State can do is "get the point across that Northwest is the only game in town." An All-Alaska line is not a possibility. Another aid is the State's "one window" permit approach being headed by Chuck Behlke, new State Pipeline Coordinator.

FEDERAL COMMITMENT -- The project is the only energy project specifically mentioned by President Carter in his recent energy speech. The federal government, says Rhett, is moving more quickly on several regulatory decisions still pending. The Incentive Rate of Return issue is to be finally decided August 8. The gas conditioning costs question is to be wrapped up September 1 "except for legal action." And the Carter-requested meeting with producers to discuss debt financing overrun guarantees will take place soon. The State will not be included among the producers in that instance, Rhett indicated.

FINANCING -- Rhett stressed the federal government's continued conviction that the line will be privately financed. "We're not convinced today-- we may be a month from now -- that it cannot be privately financed." Talk of a need for federal guarantees may be a self-fulling prophecy, Rhett suggested, with a need for federal guarantees created by people saying there is a need for federal guarantees.

In regard to possible state financing, Rhett responded, "We'd love to see it." The proposed state revenue bonds are "probably pretty well expected in the financial community." It would, said Rhett, "put a shock through the system" if the bonds are not issued. However, he added, no federal/congressional action has been taken on the change in the IRS Section 103 code change necessary for the state bonds to be issued. The request for a change in the code "has never been asked. It really has not been formally presented within the federal government."

A state equity investment would be a "much tougher" issue, Rhett said, noting that equity investments must be "prudent" and involve major philosophical questions.

"Any financial occurring at this time is a conditional form of financing...You're not dead certain whether you're buying a pig in a poke," said Rhett.

PROJECT TIMELINE --Preliminary financing must be arranged by December 31, 1979, Rhett stated. "I feel that by December 31 this year, it's either going to be positive or we've got real problems and we're going to slip another year." Asked if Alaska financial commitment was also necessary by December 31, Rhett replied, "What we're talking about this fall is not that tight a package." Alaska, he indicated, would not lose out by making a decision about state participation in project financing at a later date.
Other project dates, as outlined by Rhett, are as follows:
Preliminary financing by December 31, 1979.
Northwest application for certification by June, 1980.
Federal Energy Regulatory Commission processing of the certification application will take one year, with an additional five months allowed for litigation, bring completion of the certification process to October, 1981.
Design on the Alaska segment will be seventy percent done in 1982. Until then, Rhett said, no completely good financing estimate for the project will be available. By that time Northwest will have spent an estimated $400 million.

FEDERAL FINANCING -- In response to questions about the federal government's reluctance to participate in project financing, Rhett said that consideration of federal guarantees raises both philosophical and monetary problems. "You start guaranteeing these bonds for natural gas, what does that do -- downgrade every other federal bond for natural gas? Does this mean every major project has to have federal guarantees?"

TECHNICAL ISSUES --The proximity issue (how close the project will be constructed to the existing Alyeska oil pipeline) will ultimately be resolved, Rhett said. "There are some knotty issues there--technical and legal, particularly liability." By federal law, Alyeska has unlimited liability for the oil pipeline.

OTHER ITEMS -- Rhett regarded as "very controversial" reports indicating that early gas withdrawals may damage ultimate oil recovery at Prudhoe Bay. In regard to the Canadian segment, Rhett reaffirmed the federal support for that project, although he admitted "some stagnation" in Canadian progress. Promising an open exchange of information, Rhett plans to headquarter in D.C. until after the Candaian segment of the line is built.

Present at the meeting were Sen. Mike Colletta, Rep. Bill Miles, Sen. Bill Sumner, Rep. Chat Chatterton, Rep. Joe Hayes, Attorney General Av Gross, and State Pipeline Coordinator Chuck Behlke.

Alaska State Legislature

House of Representatives

Committee on Resources

Official Business

Pouch V
State Capitol
Juneau, Alaska 99811

August 2, 1979

To: Members of the House Resources Committee
Members of the House Interim Committee on Oil & Gas Leasing Policy

From: Mary Halloran
Research Analyst

Attached are copies of the questions sent to the Alaska Oil & Gas Conservation Commission, Mr. Hank Van Poollen and Dr. Todd Doscher for their use in preparing for the hearings on the Prudhoe Bay reservoir management.

The hearings are tentatively scheduled for the afternoon of August 6 and August 7 in the House Resources committee room.

Copies to Reps. Miles, Osterback, McKinnon, Zharoff, Carney, Cotten, Fuller, Chatterton, Eliason, Halford, Hayes, Malone and Rogers.

AGO 532462 +

PRUDHOE BAY RESERVOIR MANAGEMENT HEARING
August 6 & 7, 1979, Juneau- House Resources

QUESTIONS
For the Alaska Oil and Gas Conservation Commission

1. Please give us an overview of the basics/the mechanics of an oil reservoir.

2. What are the responsibilities and powers of the Alaska Oil and Gas Conservation Commission in regard to prudent reservoir management?

3. What plans does the Conservation Commission have to meet those responsibilities with regard to the Prudhoe Bay reservoir?

4. Has the Conservation Commission reviewed the producers' studies and preparations for secondary recovery methods, including waterflooding? How do the results of the industry's work so far correlate with the results of the studies by Van Poollen and Doscher?

5. Specifically, what are you doing to ensure that appropriate secondary recovery techniques are undertaken by Prudhoe Bay operators in sufficient time to prevent reservoir damage and to maximize ultimate oil recovery?

6. If you do not believe you have sufficient data to undertake a specific course of action, when will you have the proper amount of information?

PRUDHOE BAY RESERVOIR MANAGEMENT HEARING
August 6 & 7, 1979, Juneau - House Resources

QUESTIONS
for Mr. VanPoollen and Dr. Doscher

1. There has been considerable discussion about the pressure of of the Prudhoe Bay reservoir to date. What was the initial reservoir pressure as oil production started? What was the pressure predicted to be at this time? What is the actual pressure at this time? Is the drop in pressure indicative of any damage to the reservoir or of less ultimate recovery of oil? If the drop in pressure continues at the present rate, what kind of damage or reservoir depletion might take place and over what period of time?

2. What type of pressure maintenance is now being used? What types of secondary recovery methods should be considered for present or future use? When should pressure maintenance systems be initiated if the goal is to maximize ultimate recovery of oil?

3. Another topic receiving considerable discussion is the presence of shale in the reservoir. Does the reservoir contain a sizable amount of shale? What are the implications of the presence of shale for secondary recovery methods and ultimate oil recovery? Does the shale, for example, affect the efficiency of the recovery methods, such as gravity drainage? Waterflooding? In short, does the presence of more shale than was originally reported indicate a more immediate need for waterflooding than was originally anticipated?

4. Textbooks indicate waterflooding should begin at the bubble point, if there is no natural water drive and no gas cap drive. Assuming the textbook theory generally holds, when should waterflooding at Prudhoe Bay begin? When is the bubble point for Prudhoe Bay?

5. What analysis have you done of the various scenarios for pressure maintenance/secondary recovery methods? What have been the general results of those runs? If waterflooding is used as the pressure maintenance system, what are the ultimate oil recovery results assuming waterflooding began in year 1? In year 2? In year 3? In year 5? In year 7? In year 9? In other words, to what degree is ultimate oil recovery affected by the delay in initiating waterflooding?

6. Have you also analyzed other secondary recovery methods besides waterflooding? If so, what conclusions have you reached? Has CO_2 been considered as a method? Will it work in Prudhoe Bay? What about the use of steam injection? Could another alternative to waterflooding be more wells, spaced at, say, 80-acres? What impact would a substantial number of additional wells (above the 500 now estimated for the reservoir) have on ultimate recovery?

7. At some point, natural gas sales will commence. What effect, in general, will the withdrawal of natural gas have on the reservoir pressure? What are the implications for pressure maintenance and ultimate oil recovery?

8. What effect will different rates of production have on ultimate oil recovery? Have you done computer runs which compare the effects of waterflooding with different rates of production? If so, what are the results? What effect would a slower rate of production have on ultimate oil recovery?

9. When is it "traditional" to construct pumps, water-gathering and treatment facilities? If it is more "traditional" to construct such facilities after the field start-up, why have producers established that tradition? What are the secondary recovery techniques used elsewhere in the world? When are they initiated during field development?

10. Is delay in initiating full scale pressure maintenance reversible by over injection of outside fluids possible? If so, will it erase any damage resulting from delay with respect to ultimate recovery of oil?

11. In reviewing your work, we are dealing with both the actual reservoir and a simulated computer model. What value, if any, should we attach to the simulated performance projections? Do we get hydrocarbon ultimate recovery numbers that we can go to the bank with? Or are they just order of magnitude numbers? What degree of risk do we run in making revenue projections from model run projections? For 2 years? For 6 years? For the life of the field?
In other words, please delineate the strengths and weaknesses of 2D and 3D modeling.

12. Do we now have the capability of monitoring Prudhoe reservoir performance to the extent necessary to protect the State's interest, in particular the maximization of ultimate oil recovery? If not, what additional steps are called for?

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA — CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES
REP. BILL MILES — CO-CHAIRMAN
REP. C.V. CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

Pouch V, Juneau
465-3779

FEB 11 1980

Senator Mike Colletta
Alaska Senate

Dear Mike,

Here are the materials Van Poollen and Doscher handed out at the Friday hearing on Prudhoe Bay reservoir management.

Basically, the two agreed on two things:

1. Waterflooding should be mandatory at Prudhoe Bay;
2. Gas sales make a difference in ultimate oil recovery of less than one percent of the total oil in place, or less than 200,000,000 barrels.

They disagreed on how much oil will ultimately be recovered. Van Poollen estimates recovery ranging from 35.9% to 46.1% of the total oil in place. Doscher, on the other hand, is less optimistic, estimating about five percent less recovery (31% to 41%). The difference is substantial -- about one billion barrels of oil.

I will be preparing a detailed briefing paper on the hearing this week. But if you have any other questions, just let me know.

Sincerely,

Mary

Mary Halloran
Research Analyst

AGO 532466

the DOSCHERS GROUP *inc*
8948 wonderland park avenue
los angeles, california 90046
(213) 654-2883

February 3, 1980

Representative Bill Miles,
Co-Chairman
Joint Gas Pipeline Committee
State of Alaska
Pouch 'Y'
Juneau, Alaska 99801

Dear Representative Miles:

Enclosed you will find my report concerning the conclusions I have reached on the numerical simulation of the Sadlerochit Reservoir in the Prudhoe Bay Field as of this date.

You will find that the report is brief and unambiguous. The conclusions are in such accord with our previous studies and reports to the Legislature that I believe there is no need for any lengthy exposition nor extended explanations.

Following my visit to the Legislature this coming week I will have probably overexpended my budget by a small amount. I trust that you have found my services rewarding and useful in your deliberations concerning the Prudhoe Bay Field.

Sincerely yours,

Todd M. Doscher

TMD/jak
Enclosure

AGO 532467

ANALYSIS OF THE RESULTS OF THE NUMERICAL SIMULATION OF THE SADLEROCHIT RESERVOIR PRUDHOE BAY FIELD

February 3, 1980

Prepared for
The JOINT GAS PIPELINE COMMITTEE of the STATE OF ALASKA

AGO 532468

the DOSCHERS GROUP *inc*
8948 wonderland park avenue
los angeles, california 90046
(213) 654-2883

I. CONCLUSION CONCERNING THE NEED FOR WATERFLOODING BY THE 8TH YEAR TO MAXIMIZE PRODUCTIVITY

IN ORDER TO REACH THE PROPER CONCLUSION CONCERNING THE NEED FOR WATERFLOODING, IT IS ONLY NECESSARY TO COMPARE RUN NO. 199 (NO WATERFLOODING) WITH RUN NO. 230 (WATERFLOODING BEGUN IN 8TH YEAR), OR RUN NO. 267 (WF) WITH RUN NO. 254 (NO WF).

(THE SIGNIFICANCE OF THE DIFFERENCE BETWEEN THE TWO SETS OF PAIRED RUNS, 199/230 AND 267/254, WILL BE CONSIDERED UNDER PART III.)

BOTH OF THESE COMPARISONS SHOW THAT IN THE ABSENCE OF A WATERFLOOD THERE IS A REDUCTION OF ONE TO ONE AND ONE-HALF YEARS IN THE PERIOD DURING WHICH THE 1.5 MILLION BARREL A DAY RATE CAN BE SUSTAINED. THIS IS SO SIGNIFICANT BECAUSE SOME 500,000 BARRELS A DAY ARE LOST DURING THAT TIME INTERVAL.

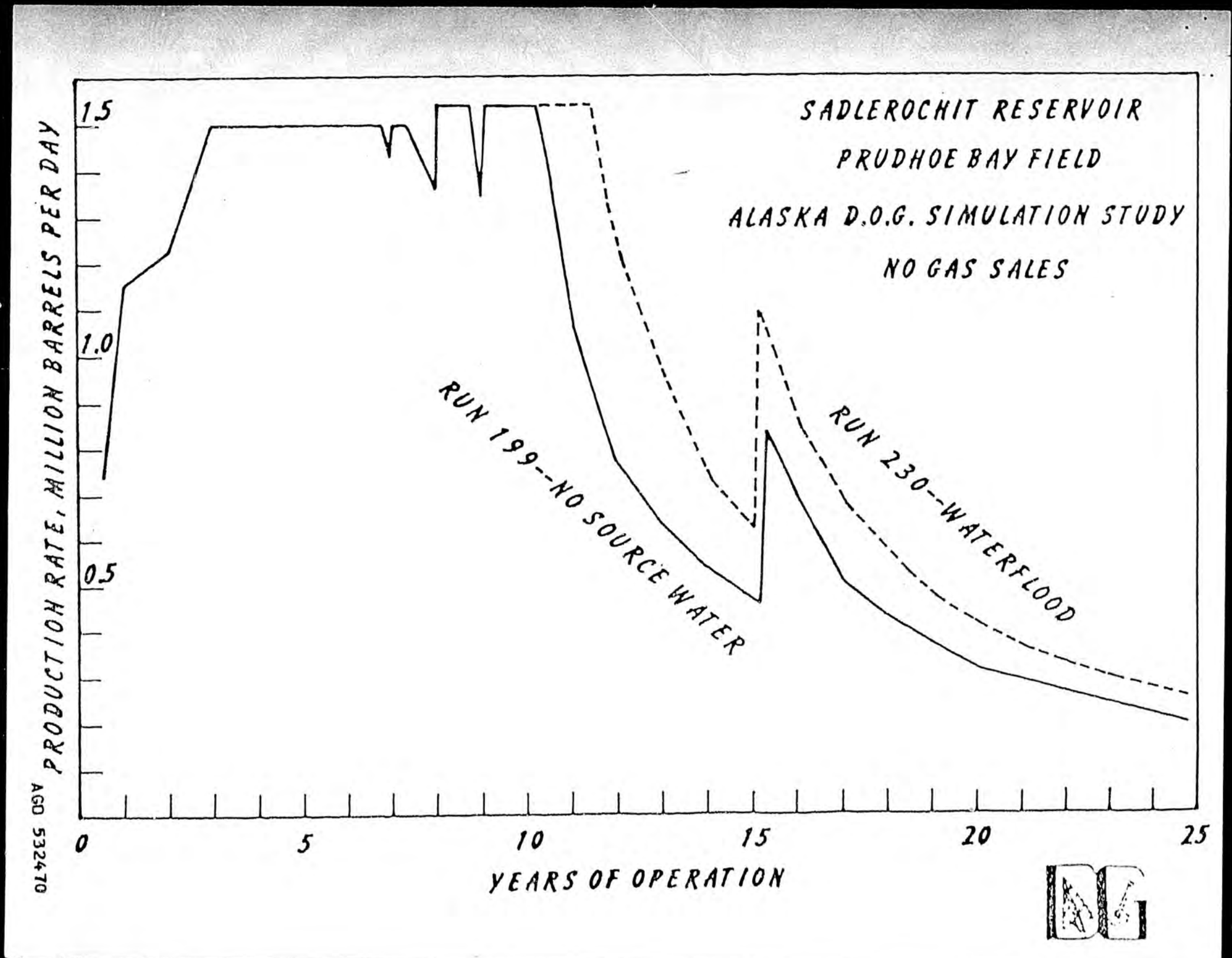
THE DIFFERENCE IN RECOVERY BETWEEN STARTING A WATERFLOOD IN THE 8TH YEAR* AND NOT DOING SO IS ONE BILLION BARRELS OF OIL AFTER 25 YEARS OF OPERATION.

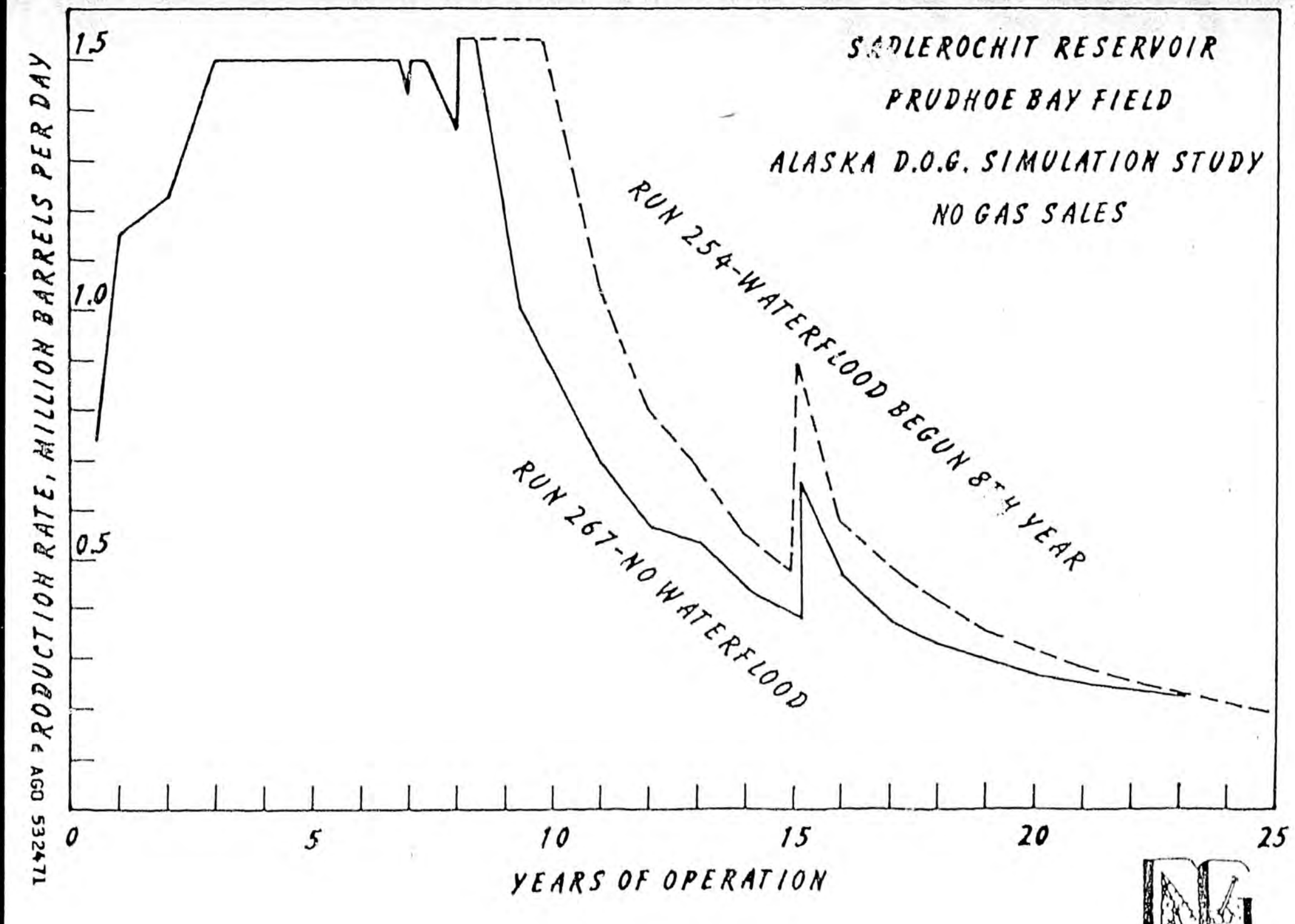
(IF THE WATERFLOOD IS DELAYED MUCH BEYOND THE 8TH YEAR, IT IS SURMISED THAT THE LOSS IN ULTIMATE RECOVERY WILL PROGRESSIVELY INCREASE SINCE IT WILL BE DIFFICULT FOR THE WATERFLOOD TO CATCH UP WITH THE NATURAL DECLINE. THE LOSS IN PRODUCTION WILL BECOME INCREASINGLY IRREVOCABLE.)

---

*INSTITUTING A WATERFLOOD PRIOR TO THE 8TH YEAR IS NOW PRACTICALLY IMPOSSIBLE SO THERE IS NO NEED TO EXPLORE SUCH AN OPTION.

the DOSCHERS GROUP inc
8948 wonderland park avenue
los angeles, california 90046
(213) 654-2883


SADLEROCHIT RESERVOIR
PRUDHOE BAY FIELD
ALASKA D.O.G. SIMULATION STUDY
NO GAS SALES
RUN 199--NO SOURCE WATER
RUN 230--WATERFLOOD
PRODUCTION RATE, MILLION BARRELS PER DAY
1.5
1.0
0.5
0
5
10
15
20
25
YEARS OF OPERATION
ADG 532410

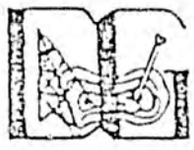

SADLEROCHIT RESERVOIR
PRUDHOE BAY FIELD
ALASKA D.O.G. SIMULATION STUDY
NO GAS SALES
RUN 254-WATERFLOOD BEGUN 8TH YEAR
RUN 267-NO WATERFLOOD
PRODUCTION RATE, MILLION BARRELS PER DAY
1.5
1.0
0.5
0
5
10
15
20
25
YEARS OF OPERATION
AGO 5324-71

II. CONCLUSION CONCERNING THE NEED FOR WATERFLOODING PRIOR TO GAS SALES
(2 BILLION CUBIC FEET PER DAY)

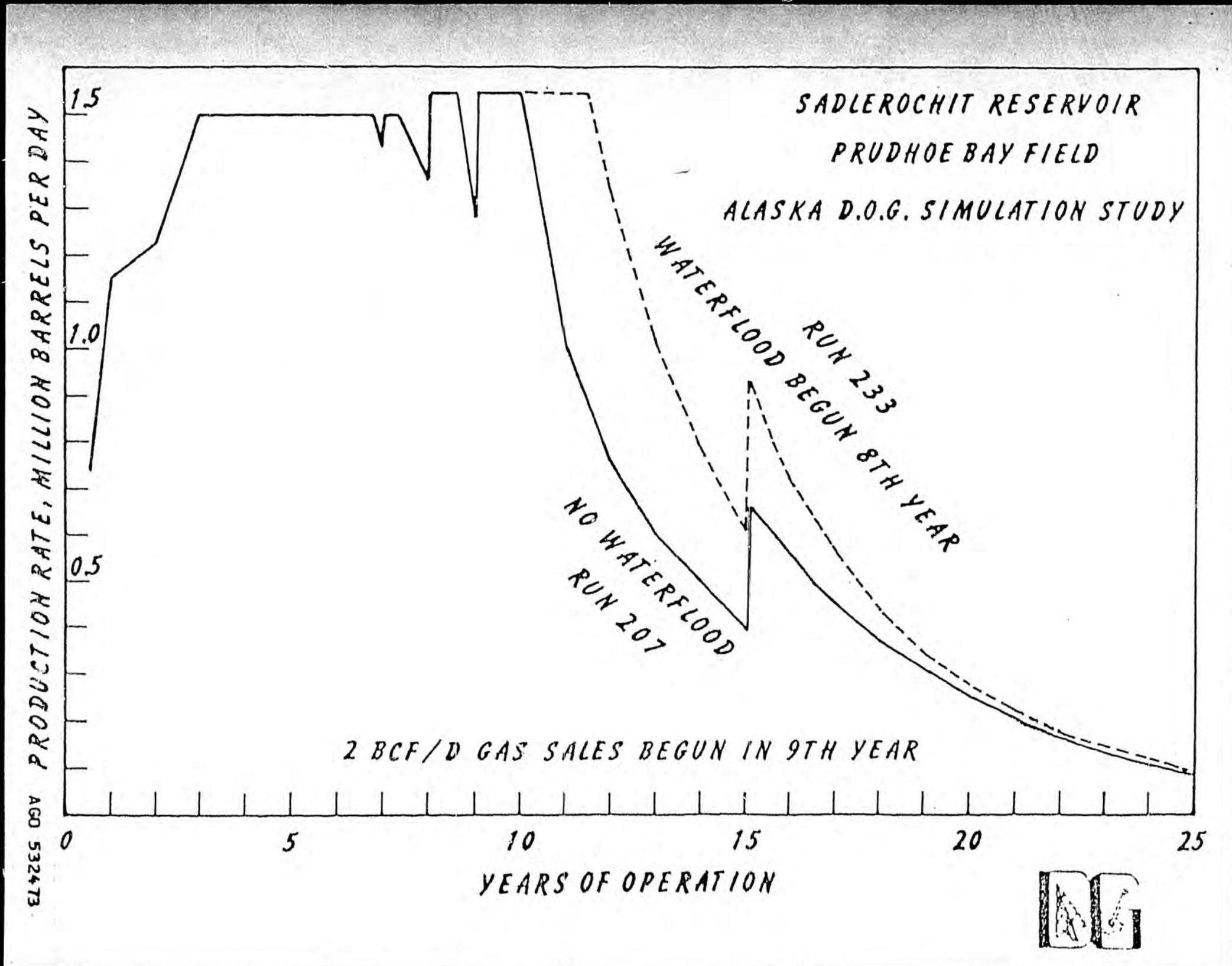
IN ORDER TO REACH THE PROPER CONCLUSION, THE ONLY COMPARATIVE RUNS AVAILABLE AT THIS TIME (FEBRUARY 1980) ARE RUN NO. 207 (NO WATERFLOODING, GAS SALES START IN 9TH YEAR) AND RUN NO. 233 (WATERFLOODING INITIATED IN 8TH YEAR, GAS SALES IN 9TH YEAR).

THIS COMPARISON SHOWS THAT WHEN GAS SALES ARE BEGUN IN THE 9TH YEAR, THERE IS A LOSS OF ONE BILLION BARRELS OF CRUDE OIL AFTER 25 YEARS OF OPERATION IF WATERFLOODING HAD NOT BEEN BEGUN IN THE 8TH YEAR.

(THERE ARE NO OTHER RUNS AVAILABLE FOR FURTHER DETAILING THE EFFECT OF GAS SALES, BUT IT IS SURMISED THAT THE EARLIER GAS SALES ARE BEGUN PRIOR TO THE BEGINNING OF WATERFLOODING, THE LOSS IN RECOVERY AFTER 25 YEARS OF OPERATION WILL INCREASE AND BECOME INCREASINGLY IRREVOCABLE.)



the DOSCHERS GROUP *inc*
8948 wonderland park avenue
los angeles, california 90046
(213) 654-2883


SADLEROCHIT RESERVOIR
PRUDHOE BAY FIELD
ALASKA D.O.G. SIMULATION STUDY
WATERFLOOD BEGUN 8TH YEAR
RUN 233
NO WATERFLOOD
RUN 207
2 BCF/D GAS SALES BEGUN IN 9TH YEAR
PRODUCTION RATE, MILLION BARRELS PER DAY
1.5
1.0
0.5
0
5
10
15
20
25
YEARS OF OPERATION
ADG 53473

III. CONCLUSION CONCERNING THE ABSOLUTE RECOVERY OF OIL FROM PRUDHOE BAY AFTER 25 YEARS OF OPERATION

IT IS UNFORTUNATELY IMPOSSIBLE AT THIS TIME TO DRAW FIRM CONCLUSIONS CONCERNING THE ABSOLUTE RECOVERY OF CRUDE OIL FROM THE PRUDHOE BAY FIELD. THE PROBLEM CAN BE SEEN IN A STUDY OF RUNS NOS. 199 AND 267.

CONSIDER RUN NO. 199 (NO WATERFLOODING, NO GAS SALES): A PRODUCTION RATE OF 1.5 MILLION BARRELS A DAY IS REACHED IN THE 3RD YEAR. IN ORDER TO MAINTAIN THIS RATE IN VIEW OF A PRONOUNCED TENDENCY FOR MANY WELLS TO "GAS OUT", IT IS NECESSARY TO CONDUCT A LARGE NUMBER OF WELL RE-COMPLETIONS:

DURING THE 5TH YEAR	8 RE-COMPLETIONS
DURING THE 6TH YEAR	153 RE-COMPLETIONS
DURING THE 7TH YEAR	189 RE-COMPLETIONS
DURING THE 8TH YEAR	21 RE-COMPLETIONS
DURING THE 9TH YEAR	(SEE BELOW)
DURING THE 15TH YEAR	102 RE-COMPLETIONS

THESE RE-COMPLETIONS ESSENTIALLY COMPRISE CEMENTING PERFORATED INTERVALS AND RE-PERFORATION OF LOWER INTERVALS. THE NUMBER OF SUCH WORK-OVERS IS HIGH AND IT IS BEYOND OUR KNOWLEDGE AT THIS TIME TO ASCERTAIN WHETHER THE ABSOLUTE NUMBER IS FEASIBLE. HOWEVER OF FAR GREATER IMPORTANCE IS THE IMPLICIT ASSUMPTION THAT THESE LARGE NUMBER OF RE-COMPLETIONS CAN BE AS EXACTINGLY SPECIFIED IN THE REAL WORLD OF FIELD OPERATIONS (COMPARED TO PUNCHING A CARD IN THE SIMULATION) AND EVEN MORE IMPORTANT THAT THERE WILL BE A SUCCESS RATIO OF 100%.

the DOSCHERS GROUP inc
8948 wonderland park avenue
los angeles, california 90046
(213) 654-2883

III. CONCERNING ABSOLUTE RECOVERY (CONTINUED)

FURTHER, IN RUN NO. 199, THERE HAS BEEN AN ADJUSTMENT IN THE 9TH YEAR OF THE "WELL FACTOR" OF 384 WELLS. THIS EFFECTIVELY SURPRESSES EXCESSIVE GAS/OIL RATIOS (WHETHER OR NOT DUE TO CONING). THIS ADJUSTMENT MAY BE JUSTIFIED, BUT AT THIS TIME WE CANNOT ATTEST TO ITS VALIDITY.

IN ORDER TO TEST THE SENSITIVITY OF THE RESULTS TO THIS ADJUSTMENT, RUN NO. 267 WAS UNDERTAKEN AT OUR REQUEST. THE WELL FACTORS WERE NOT ADJUSTED IN THE 9TH YEAR.

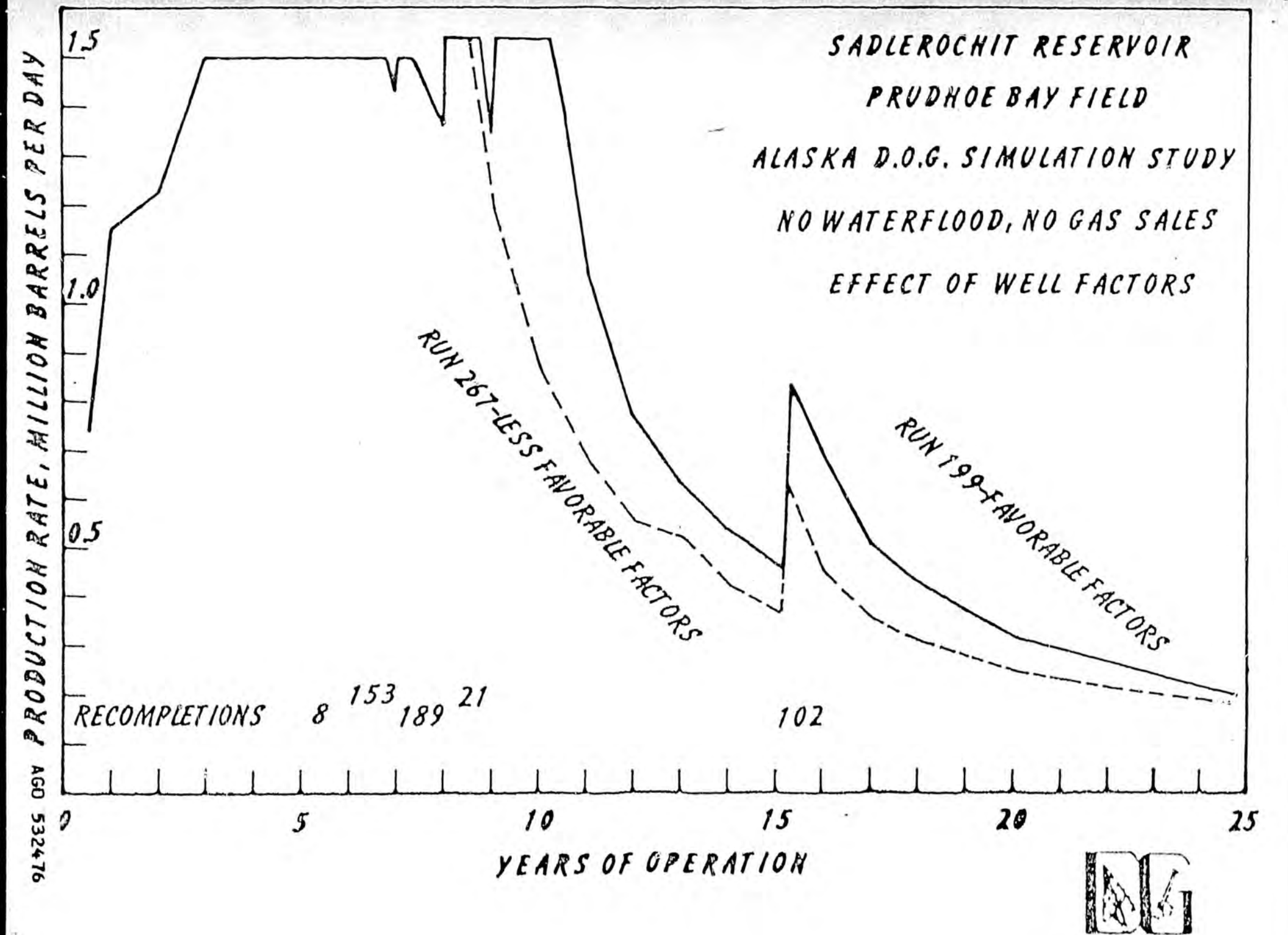
THUS, ASSUMING OPTIMUM WELL FACTORS AND THAT THE RE-COMPLETIONS CAN BE SPECIFIED AS EXACTINGLY AS IN THE PAPER STUDY AND MEET WITH 100% SUCCESS, THE RECOVERIES LISTED IN THE 3RD COLUMN OF THE TABLE MAY BE ANTICIPATED ....

IF WELL FACTORS PROVE TO HAVE UNDERESTIMATED SIGNIFICANCE OF CONING, THEN THE RECOVERIES OF CRUDE OIL ACCORDING TO THE DIFFERENT OPTIONS MAY DECREASE TO THE LEVELS SHOWN IN THE 4TH COLUMN.

OPTIONS THAT HAVE NOT YET BEEN STUDIED ARE INFILL DRILLING TO 80 ACRES AND DECREASED OFFTAKE RATES IN THE FIRST DECADE OF OPERATION. BOTH OF THESE MAY CONTRIBUTE TO HIGHER ULTIMATE RECOVERY BUT WILL NOT INFLUENCE RELATIVE EFFECTS OF WATER-FLOODING AND GAS SALES.

WATERFLOODING	GAS SALES	25-YR RECOVERY (HIGH)	25-YR RECOVERY (LOW)
NO	NO	7.9 BILLION	6.4 BILLION
NO	9TH YEAR	7.5 BILLION	6.0 BILLION
8TH YEAR	NO	8.8 BILLION	7.3 BILLION
8TH YEAR	9TH YEAR	8.5 BILLION	7.0 BILLION

the DOSCHERS GROUP *inc*
8948 wonderland park avenue
los angeles, california 90046
(213) 654-2883


SADLEROCHIT RESERVOIR
PRUDHOE BAY FIELD
ALASKA D.O.G. SIMULATION STUDY
NO WATERFLOOD, NO GAS SALES
EFFECT OF WELL FACTORS
PRODUCTION RATE, MILLION BARRELS PER DAY
1.5
1.0
0.5
RUN 267-LESS FAVORABLE FACTORS
RUN 199-FAVORABLE FACTORS
RECOMPLETIONS
8
153
189
21
102
0
5
10
15
20
25
YEARS OF OPERATION
A&G 5324-76

IV. OVERALL CONCLUSIONS AND RECOMMENDATIONS

THE NUMERICAL SIMULATION OF THE SADLEROCHIT RESERVOIR IN THE PRUDHOE BAY FIELD HAS BEEN REWARDING TO THE STATE OF ALASKA.

IT HAS CONFIRMED THE IMPORTANCE OF WATERFLOODING, AND ESPECIALLY THE IMPORTANCE OF WATERFLOODING PRIOR TO GAS SALES IF THE MAXIMUM POTENTIAL OF PRUDHOE BAY OIL PRODUCTION IS TO BE REALIZED BY THE STATE AND THE NATION. GAS SALES EVEN WHEN DELAYED TIL THE 9TH YEAR AFTER HAVING INSTITUTED A WATERFLOOD IN THE 8TH YEAR RESULTS IN A LOSS OF ULTIMATE RECOVERY AFTER 25 YEARS OF OPERATION.

THE STUDY AT THIS TIME STILL LEAVES OPEN THE EXACT ULTIMATE RECOVERY TO BE ACHIEVED ACCORDING TO ANY ONE OPTION BECAUSE OF QUESTIONS CONCERNING THE EFFICACY OF WELL RE-COMPLETIONS AND THE EXACT RATIO OF RELATIVE PERMEABILITY OF GAS TO OIL THAT WILL CONTROL THE GAS/OIL RATIO AS DEPLETION ADVANCES. THE STUDY MUST BE MAINTAINED IN AN EVERGREEN STATE IN ORDER FOR THOSE DELEGATED BY THE STATE TO CONSERVE AND UTILIZE THE STATE'S RESOURCES FOR THE MAXIMUM BENEFIT TO THE STATE TO PERFORM THEIR JOB EFFICIENTLY.

THE STUDY HAS CONFIRMED THAT NO LESS THAN 12 BILLION BARRELS OF CRUDE OIL WILL REMAIN IN THE SADLEROCHIT RESERVOIR AT THE CONCLUSION OF CONVENTIONAL PRIMARY AND SECONDARY RECOVERY OPERATIONS. ALTHOUGH THE PROMISE OF TERTIARY RECOVERY IS STILL TO BE PROVEN, AGGRESSIVE RESEARCH STUDIES INTO THE POSSIBILITY OF TERTIARY RECOVERY SHOULD BE INSTITUTED NOW.

the DOSCHERS GROUP inc
8948 wonderland park avenue
los angeles, california 90046
(213) 654-2883

the DOSCHERS GROUP *inc*
8948 wonderland park avenue
los angeles, california 90046
(213) 654-2883

February 6, 1980

Representative Bill Miles, Co-chairman
Joint Gas Pipeline Committee
Alaska State Legislature
Juneau, Alaska

Dear Representative Miles:

Your telegram this afternoon arrived following completion of my report. I believe the matters you refer to are covered in the report, but I am offering this letter as a supplement in the hope that it will provide you with the requested elaboration.

You have raised the question of a difference in opinion existing between the D.O.G. and myself concerning one of the parameters used in the simulation and the efficacy of the well recompletions that have been built into the performance of the reservoir.

Before addressing these matters, I want to reemphasize the first two conclusions that I have drawn from the study. First, a water flood instituted by the eighth year will prolong the maximum producing rate of 1.5 million barrels a day by one to two years, and result in an increase in ultimate recovery (by the 25th year) of one billion barrels of crude oil. Second, gas sales starting as late ar ninth year result in a further loss in production of an additional half billion barrels of oil if water flooding is still not implemented.

The relative effects of water flooding and gas sales are not at all affected by the two matters about which you surmise there is some difference of opinion.

Now, in order to maintain the desired production rate of 1.5 million barrels a day after the 5th year, a large number of well re-completions were written into the simulated operation of the reservoir. Wells which went to high gas/oil ratios were plugged back and then recompleted in other intervals. This is an entirely correct operation, and one which will be pursued by the operators.

The number of recompletions is quite large, several hundred wells are worked over in a period of two years, and every attempted recompletion is a successful one. The wells gas out rapidly, and the time slot available for the work-over in order to maintain productivity is severely limited. I hesitate to believe that in the real world the accuracy in the identification of recompletion prospects and the successful implementation of such work-overs will be 100%.

Considering the probability that water flood facilities would be being installed and some new drilling being continued, there could be signficant problems merely in the deployment of the expertise required for conducting the necessary work-over operations.

Themore than 100 re-completions specified in the simulation as occurring in the 15th year are not as critical in regards to timing as the earlier re-completions, but here again less than 100% success will decrease the production rate and the ultimate recovery to be anticipated in any real time duration of operations.

Finally, there is the question of the well factors, viz., the relative permeability functions assigned to the well bore. Unfortunately the well function can not be predicted in any absolute sense. It is one of the parameters that are "tuned-in" to achieve the history match between actual and simulated performance. Because of the speed of closure of the study in recent weeks, I have not had the opportunity to study some detailed aspects of the simulations. Such study has been hindered because the data released to me did not have details on the saturation and pressure history of individual grid blocks. The assignment of well factors appeared to me to be carried out in a somewhat arbitrary (possibly justifiable) fashion, and this is why I cannot subscribe to the optimism that was introduced.

Adding together the potential effects of a less than perfect program of well recompletions, and less optimistic well factors there is a signficant probability that neither the production rate of 1.5 million barrels a day will be maintained as long nor the ultimate recovery be as high as that predicted by the more optimistic runs. For any of the options considered, these two effects might lower recovery by one to one and a half billion barrels of oil as an outside limit.

Bear in mind that these effects are superimposed on the relative effects of such options as water flooding and gas sales. Further, that such options as infill drilling, say to 80 acres, pattern waterflooding (rather than peripheral), and somewhat decreased offtake rates may have signficant effects.

The model is now ready for extended-in-time history matching, and the exploration of such issues as noted in the preceding paragraph.

Sincerely yours,

Todd M. Doscher.

OBJECTIVES

evaluate oil recovery

with or without source water injection

with or without gas sales

AGO 532480

Exhibit 1, H. K. van Poollen and Associates, Inc. 2/8/80

BOUNDARY CONDITION

max. field take off _____ 1.5 million bbls/day

gas sales _____ 2.0 billion cf/day

max. source water injection _ 2.0 million bbls/day

max. resvr. press. 3900 psi during source water inj.

start of source water injection _____ mid 1984

start of gas sales _____ mid 1985

field cut off rate _____ 100,000 bbls/day

produced water to be reinjected _____ mid 1981

artificial lift

low pressure gathering system

original hydrocarbons in place

stock tank oil _____ 20,5 billion bbls

solution gas _____ 14.9 trillion cf

gas cap gas _____ 23.4 trillion cf

AGO 532481

Exhibit 2, H. K. van Poollen and Associates, Inc. 2/8/80

EFFECT OF GAS SALES AND/OR SOURCE WATER INJECTION ON OIL RECOVERY

case	gas sales	source water injection	life years	oil recovery* % orig. oil in place	ultimate* recov. billion bbls
A	NO	NO	36.3	40.8	8.42
B	NO	YES	37.5	46.1	9.51
C	YES	NO	24.2	35.9*	7.42
D	YES	YES	26.6	45.4	9.37

AGO 532482

* without optimum recompletions

* gas coning may reduce oil recoveries

further work is recommended

Exhibit 3, H. K. van Poollen and Associates, Inc. 2/8/80

EFFECT OF SOURCE WATER INJECTION ON OIL RECOVERY

(B oil recovery) - (A oil recovery) = 46.1 - 40.8 = 5.3%

no gas sales cases

(D oil recovery) - (C oil recovery) = 45.4 - 35.9 = 9.5%

gas sales cases

or

average additional oil recovery due to source water injection

= 7.4% or 1.5 billion bbls of oil

AGO 532483

Exhibit 4, H. K. van Poollen and Associates, Inc. 2/8/80

EFFECT OF GAS SALES ON OIL RECOVERY

(A oil recovery) - (C oil recovery) = 40.8 - 35.9* = 4.9%
without source water cases

(B oil recovery) - (D oil recovery) = 46.1 - 45.4 = 0.7%
with source water cases

or

0.14 billion bbls of oil

AGO 532484

* without optimum recompletion

Exhibit 5, H. K. van Poollen and Associates, Inc. 2/8/80

CONCLUSIONS

A source water injection program:

1. Results in 5% to 9% additional oil recovery
2. Permits gas sales with no appreciable loss of oil recovery
3. Is mandatory in the Prudhoe Bay field

AGO 532485

Exhibit 6, H. K. van Poollen and Associates, Inc. 2/8/80

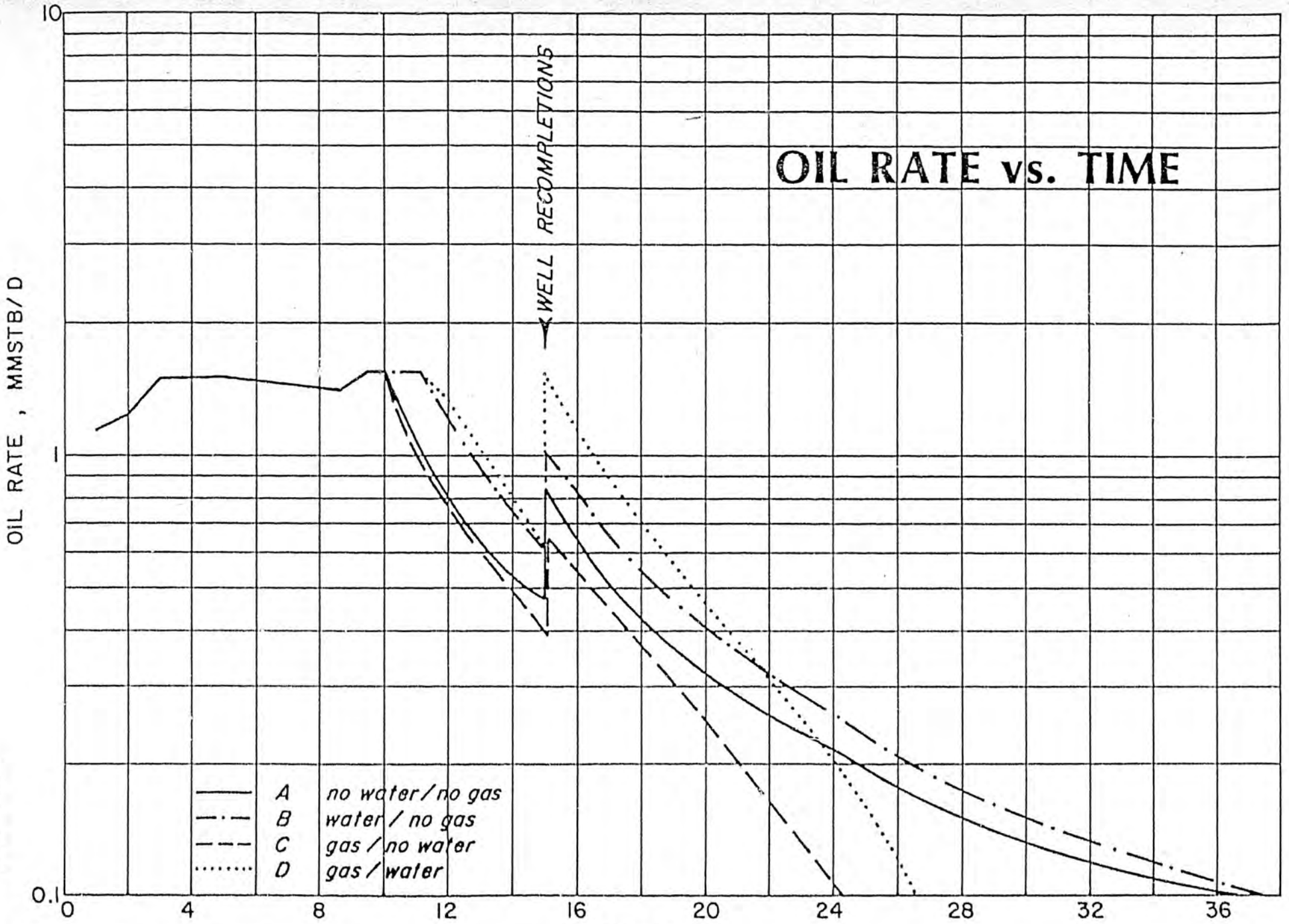


Exhibit 7, H. K. van Poollen and Associates, Inc. 2/8/80

AGO 532486

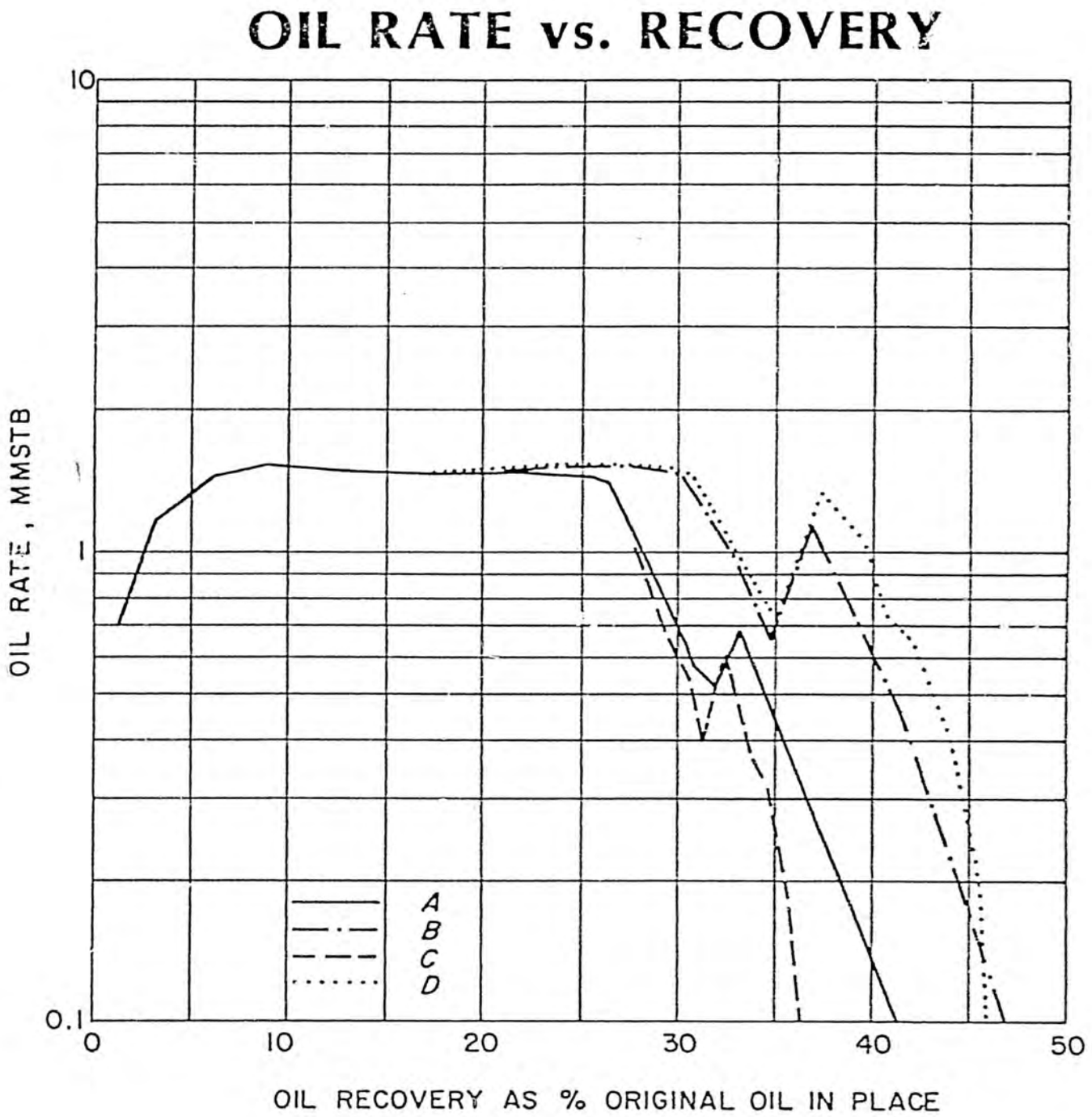


Exhibit 8, H. K. van Poollen and Associates, Inc. 2/8/80

INPUT DATA

SPECIFIC VALUES FOR EACH OF THE FOLLOWING PARAMETERS ARE ASSIGNED EACH NODE IN THE GRID SYSTEM:

PERMEABILITY.	GRID DIMENSIONS
POROSITY.	INITIAL SATURATION FOR EACH PHASE.
THICKNESS.	INITIAL PRESSURE.
ELEVATION.	ROCK COMPRESSIBILITY.

FLUID CHARACTERISTICS ARE ASSIGNED BY THE FOLLOWING RELATIONSHIPS:

- OIL FORMATION VOLUME FACTOR VS. PRESSURE.
- WATER FORMATION VOLUME FACTOR VS. PRESSURE.
- GAS FORMATION VOLUME FACTOR VS. PRESSURE.
- OIL VISCOSITY VS. PRESSURE.
- WATER VISCOSITY VS. PRESSURE.
- GAS VISCOSITY VS. PRESSURE.
- SOLUTION GAS-OIL RATIO VS. PRESSURE.
- SOLUTION GAS-WATER RATION VS. PRESSURE.
- LIQUID TO GAS RATIO VS. PRESSURE.
- OIL DENSITY.
- GAS DENSITY.
- WATER DENSITY.

THE INTERACTION OF FORCES BETWEEN ROCK AND FLUIDS ARE GIVEN BY THE FOLLOWING SATURATION DEPENDENT FUNCTIONS:

- RELATIVE OIL PERMEABILITY.
- RELATIVE WATER PERMEABILITY.
- RELATIVE GAS PERMEABILITY.
- CAPILLARY PRESSURE BETWEEN OIL AND WATER
- CAPILLARY PRESSURE BETWEEN GAS AND OIL.

SPECIFIC WELL DATA FOR APPROPRIATE GRID NODES AS FOLLOWS:

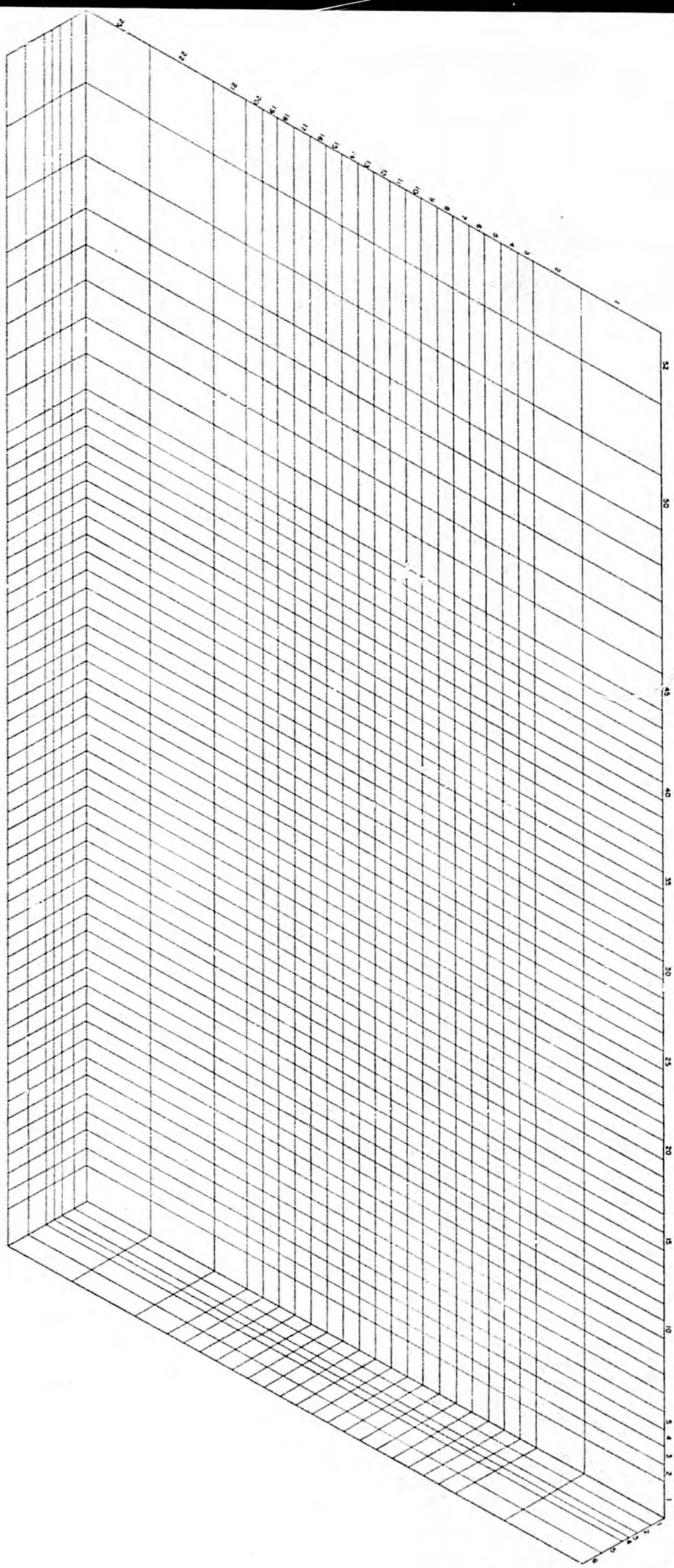
- PRODUCING INTERVAL.
- OIL PRODUCTION RATE VS. TIME.
- WATER PRODUCTION RATE VS. TIME.
- GAS PRODUCTION RATE VS. TIME.
- OBSERVED PRESSURES VS. TIME.

Costello

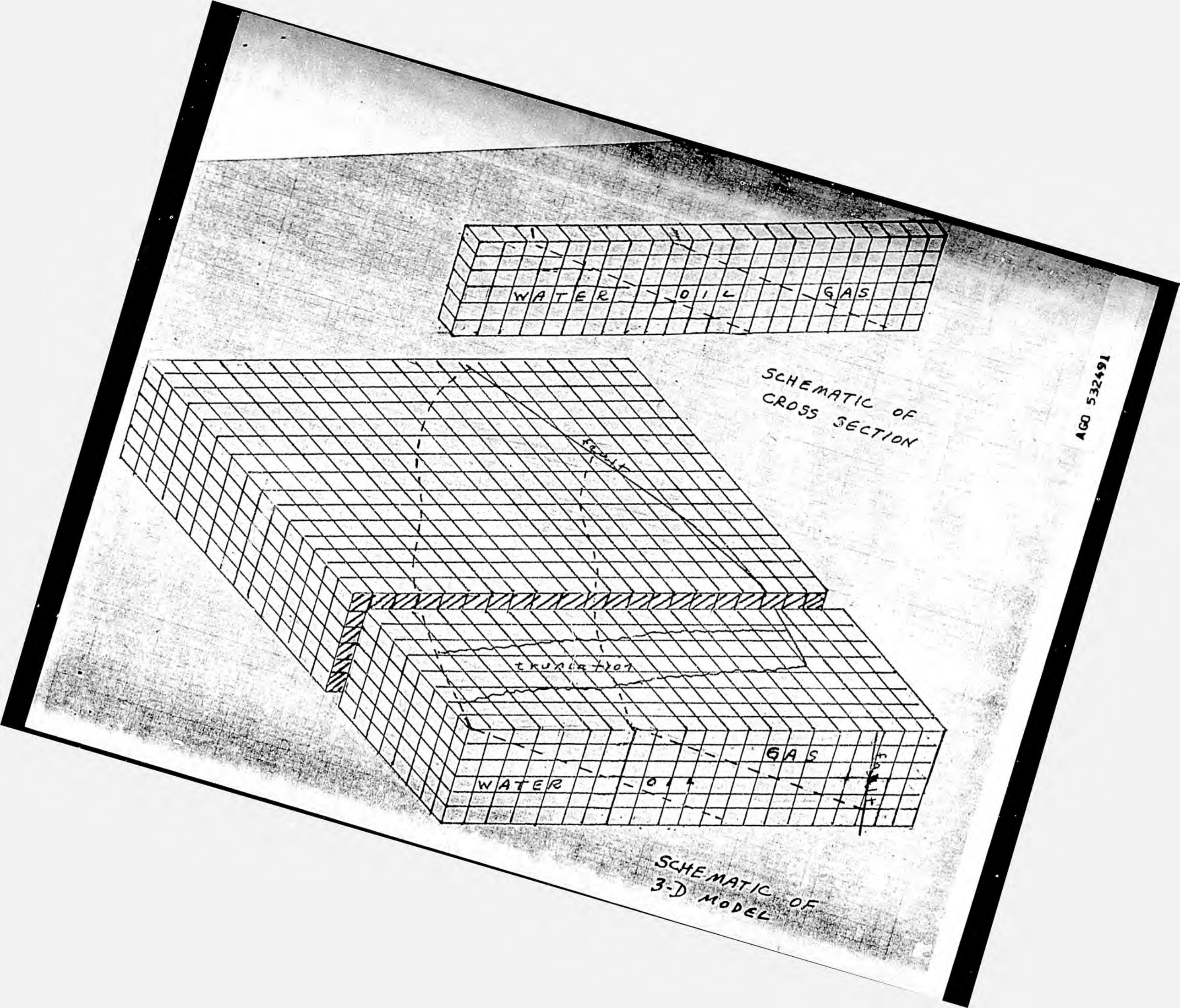
20 15 10 5 4 3 2 1

6 5 4 3 2 1

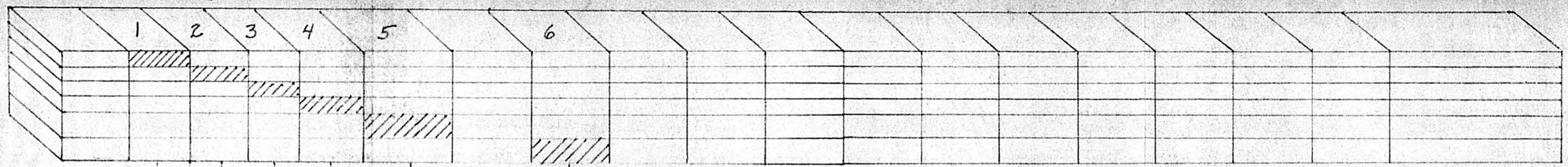
AGO 532489

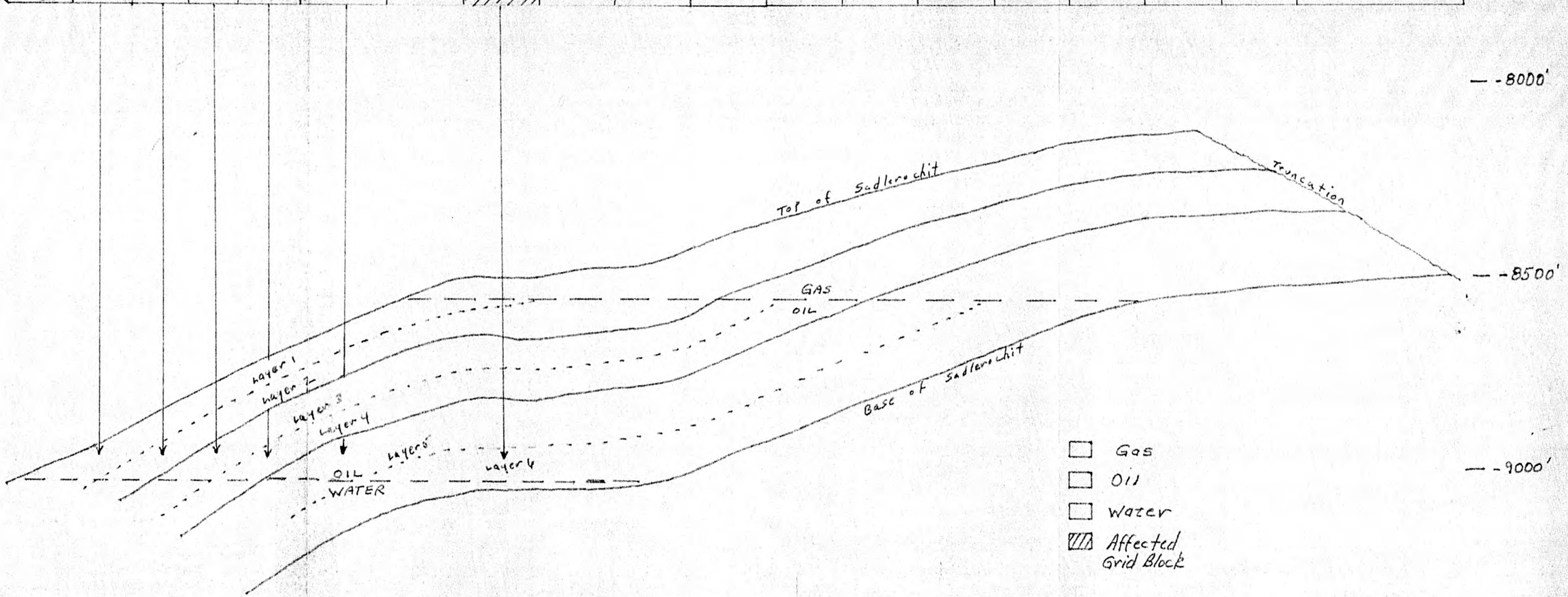


AGO 532490


WATER
OIL
GAS
SCHEMATIC OF
CROSS SECTION
AGO 532491
truncation
WATER
OIL
GAS
fault
SCHEMATIC OF
3-D MODEL

SCHEMATIC OF WATER INJECTION BY GRID BLOCK





AGO 532492 L

AGO 532492

SCOMM

#14:2

FULLER

PRUDHOE BAY RESERVOIR MANAGEMENT HEARINGS
August 6 & 7, 1979 - Juneau, House Resources

QUESTIONS
for Producers

1. The history of oil production both nationally and worldwide is not encouraging in that physical waste was long the rule rather than the exception. What specific reassurances can the industry give us that such will not be the case with the Prudhoe Bay reservoir?

2. Have producers done an economic analysis of the cost of waterflooding? By that, we mean what are the capital and operating costs of waterflooding? What are the most likely benefits in terms of oil recovery? What is the discount rate that you are going to use to relate those future benefits to present costs? Is there a time limit beyond which it would be no longer profitable to waterflood from the producers' point of view? If so, when is that time limit?

3. Given the different discount rates used by the State and the oil industry, what might be a profitable investment from the State's point of view may only be a marginal investment from industry's perspective. Is there any way, then, of alleviating this potential conflict regarding secondary recovery at Prudhoe Bay?

4. Would a slower rate of production impact secondary recovery methods? What effect would a slower rate of production have on ultimate oil recovery?

5. What is the timetable for decisions and actions on secondary recovery methods? What results do you expect from using these methods in terms of increasing oil recovery?

6. The Alaska Oil and Gas Conservation Commission reported coning of certain ARCO wells which have subsequently been shut down. Why did the coning occur? What damage resulted to the field? Would a slower production rate for those individual wells have prevented the coning?

7. Even if mid-1984 remains the target date set by industry for waterflooding to begin, why isn't construction of the project begun sooner? Isn't this project, like other capital-intensive projects, going to cost more and more as the years pass? Will the waterflooding project construction create construction jobs? How many?

PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

HALLORAN

STATE OF ALASKA
THE LEGISLATURE

LEGISLATIVE AFFAIRS AGENCY

POUCH Y - STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

ENERGY BACKGROUND REPORT FOR LEGISLATORS
October 31, 1978

CONTENTS

	Page
Alaskan Northwest may be forced to seek federal financing for gas pipeline	1
IRS exemption for pipeline bonding authority fails to pass Congress	3
Passage of natural gas bill boosts pipeline	4
FERC report favors 1260-psig pressure for gas pipeline	6
Gas conditioning facilities to cost about $2 billion	7
Department of Natural Resources selects firm to promote petrochemicals	8
Canadian decisions on gas exports will affect Alaska Highway gas pipeline	9
Beaufort Sea sale faces obstacles	10
State will seek permission to export royalty oil to Japan	13
State considers Foothills oil pipeline proposal	14
Congress approves procedure for selecting west-to-east oil pipelines	15
Petroleum revenues fall below pre-production expectations	17
Alpetco continues search for petrochemical facility site	21
State appeals tanker law decision	21
OPEC may raise oil prices	23
Congress approves stock ownership plan	23
Appendix: Prudhoe Bay oil price and destination analysis, July 1977 through August 1978	

Compiled by Kay Brown, Research Analyst

AGO 532494

ALASKAN NORTHWEST MAY BE FORCED TO SEEK FEDERAL FINANCING FOR GAS PIPELINE

The Alaskan Northwest pipeline consortium says it will not be able to secure private financing for the Alaska Highway gas pipeline if a proposed "incentive rate of return" rule is adopted in its present form.

In comments filed in early October with the Federal Energy Regulatory Commission (FERC), Alaskan Northwest said rulemaking on the incentive rate of return has had "a chilling effect" on the project and brought financing negotiations "to a standstill."

The partnership also said it may limit its equity contributions to the project unless "major risks and uncertainties" are resolved in its favor.

Imposition of the incentive rate of return would allow the pipeline companies and other equity investors to earn a high rate of return if the project were constructed within or under budget, but would reduce earnings if the project ultimately cost more than projections. The greater the cost overrun, the lower the allowed rate of return would be.

This method for controlling cost overruns was mandated in the President's Decision and Report to Congress selecting the Alcan route over the El Paso and Arctic proposals, but its specific structure and method of implementation were left for FERC to resolve.

FERC issued its first incentive rate of return (IROR) proposal May 8. After receiving comments from 24 interested parties, the commission issued a revised proposal September 15.

"A Commission order retaining any substantial vestige of the September 15 structure will be incompatible with private sector financing of the project," Alaskan Northwest said in its response to the revision. "Alaskan Northwest's plans for private financing cannot be realized under the Commission's proposal. A final rule incorporating the September 15 structure will produce such a fundamental change in the economic parameters of the project that Alaskan Northwest will have no chance to obtain private financing and will be required to seek federal government financial assistance and support."

FERC's September 15 incentive rate of return proposal sets out a complicated method for arriving at the allowed return to equity, and for illustrative purposes suggests this rate of return might be about 17 percent with a 30 percent cost overrun. (FERC says the actual permissible rates of return will be determined in a later evidential proceeding.) A normal rate of return on a regulated pipeline of similar operating risk is about 13 percent, according to FERC.

While the allowed rate of return is quite high if the project is built within or under budget, investors may perceive the risk of huge overruns as so great that they will be unwilling to invest in the project.

In its comments, Alaskan Northwest said FERC's current IROR proposal subjects the partnership to a penalty for all project delay, whether or not caused by the partnership.

Government-caused delays, for which the partnership says it is not responsible and should not be penalized, include the legislative stalemate over natural gas pricing, which already has delayed the project for more than a year; FERC delay in resolving the incentive rate of return; inaction by President Carter and Congress on the appointment and confirmation of a Federal Inspector; and lack of a decision on pipeline design and pressure.

ALASKA'S POSITION OF, NORTHWESTS

"Any variable rate of return mechanism which imposes the financial burden of government-caused delay on equity participants by reducing their allowed rate of return is a system which precludes equity financing," Alaskan Northwest said.

Alaskan Northwest also objected to "an extraordinary degree of reliance by the Commission on Alcan's March 1977 cost estimates as the basis for establishing the variable rate of return structure." Alaskan Northwest maintained that the incentive rate of return should be based on the capital cost estimates submitted to and accepted by FERC immediately prior to certification.

FERC has failed to act with "expedition and certainty" in its rulemaking, Alaskan Northwest said, since additional proceedings and hearings will be required at unknown times in the future in order to finally resolve the range of permissible return and other matters.

"It is without exaggeration that we say that the Commission has given us nothing upon which we can rely at this time," the partnership said. "The actual impact of the IROR structure remains unknown and unknowable."

The State of Alaska, in its comments on the September 15 proposal, did not oppose the IROR formula but did ask FERC to speed up its proposed timetable of proceedings.

"As all those intimately concerned with the gas project know, the issues involved are complex and difficult and the Commission has not been able to adhere to even its tentative timetable with respect to such matters as this rulemaking or its pressure and size inquiry. Therefore, Alaska asks that the Commission give consideration to its schedule for implementing the incentive rate of return in light of the financing and construction timetables of the project," the state said.

IRS EXEMPTION FOR PIPELINE BONDING AUTHORITY FAILS TO PASS CONGRESS

Congress adjourned for the year without approving a change in Section 103 of the Internal Revenue Service Code, a change that would have been required for a state bonding authority approved last year to issue $1 billion in tax-exempt bonds for the gas pipeline.

The IRS code change apparently was blocked because Sen. Henry Jackson of Washington, chairman of the Senate Committee on Energy and Natural Resources, and other senators did not want anything to jeopardize a House vote on the natural gas pricing bill, part of President Carter's national energy package. The Treasury Department also opposed the change on grounds it would cause a loss in federal income.

There is some confusion and disagreement about the events surrounding consideration of this proposal.

According to Deming Cowles, an aide to Sen. Mike Gravel, the key reason the proposal failed to gain support was that Alaskan Northwest "didn't establish a record showing the need, desirability and benefit to consumers."

"It says conclusively in the President's Decision that the pipeline is supposed to be privately financed without any subsidy whatsoever, and yet here was Northwest asking for what some people consider a direct federal subsidy. People wanted to know whether the situation had changed. People wanted to see facts and figures," Cowles said.

"There was also negative reaction because the state was not issuing the bonds itself," he said. "People were asking, 'Why should federal taxpayers have to subsidize gas consumers, since not every federal taxpayer is a gas consumer?' There were some fairly sophisticated arguments against it, and Northwest simply didn't lay the groundwork."

The industrial development bond proposal was never formally considered by either house of Congress, although Gravel attempted to rally support at the last minute. Gravel first attempted to get the change included in the conference committee version of the energy tax bill, but it was rejected there because it was outside the scope of the conference.

Gravel circulated two different drafts of the proposal to key senators. The first would have limited the amount of bonds that could be issued to $3.2 billion and included funding for the North Slope conditioning facilities. The other placed no limit on the amount of bonds that could be issued. When it became clear the proposal would fail on the floor, Cowles said, Gravel decided not to pursue it.

Northwest lobbyist Bill Foster said the Gravel amendment was in fact introduced but never printed, although Cowles denies this. Foster said the increases in the amounts to be issued were Gravel's idea and were not requested by Northwest.

Northwest Alaskan officials told the legislative Interim Committee on Gas Pipeline Financing in September that they had postponed seeking the IRS change until Congress acted on the natural gas bill. Final congressional action on the natural gas bill, as well as the other parts of the President's energy package, did not come until the closing hours of the 95th Congress.

"It was the political judgment of Northwest not to proceed until the last minute. They came to us at the last minute and by then it was too late," Cowles said.

Cowles said Gravel, chairman of the Senate Finance Subcommittee on Energy and Foundations, probably will hold hearings on the proposed IRS change early in the next session of Congress.

PASSAGE OF NATURAL GAS BILL BOOSTS PIPELINE

Although the failure of Congress to pass the IRS code change might be considered a setback for the Alaska Highway gas pipeline, passage of the natural gas pricing bill is viewed by most as a major step forward.

The bill, which will gradually deregulate some new gas prices and extend regulatory controls to intrastate sales, provides 12 different prices for gas, depending on when and where a well was drilled and whether gas from that well has ever been sold interstate. Carter is expected to sign the entire energy package, including the natural gas pricing bill, in early November.

The bill is important to the Alaska Highway gas pipeline because it sets a ceiling price for North Slope gas and will allow the cost of expensive Alaska gas to be averaged with cheaper Lower 48 supplies, a device known as "rolled-in" pricing.

Specifically, the bill sets a Prudhoe Bay wellhead ceiling of $1.45 per million Btus as of April, 1977, plus an annual inflation factor (which with 6 percent annual inflation would make it roughly $2.25 per million Btus in 1984). This is a ceiling price, and it is uncertain whether the producers will be able to get the pipeline companies to pay that much. In addition to the value of the gas itself, the producers will be allowed to recover current state severance taxes (and future severance tax increases, provided they don't discriminate between interstate and intrastate sales) and their gathering and conditioning costs in the price they charge the pipeline companies.

The pipeline tariff and the wellhead ceiling will be passed on to consumers under the rolled-in mechanism. If the severance taxes and producer-borne gathering and conditioning costs push the price to the pipeline companies above the ceiling, FERC will decide whether the extra costs will be rolled-in or priced on an incremental basis to industrial and other low-priority users.

The bill specifies two categories of costs that will be priced under the incremental pass-through. State severance taxes enacted after December 1, 1977, and gathering and conditioning costs borne by parties other than the producers (presumably the pipeline companies or other gas purchasers) will be priced incrementally to industrial users.[1]

Of the rolled-in pricing provision, the joint conference report accompanying the legislation says: "The conferees agreed to provide rolled-in pricing for natural gas transported through the Alaska Natural Gas Transportation System and for the cost of transportation because they believed that private financing of the pipeline would not be available otherwise. Rolled-in pricing is the only Federal subsidy, of any type, direct or indirect, to be provided for the pipeline."

The fact that Congress allowed rolled-in pricing only for gathering and conditioning costs borne by the producers, and not for gathering and conditioning costs borne by other parties, seems to indicate its desire that the oil companies assume responsibility for financing and building the North Slope conditioning facilities, estimated to cost about $2 billion.

Passage of the natural gas pricing legislation clears the way for negotiations to begin between the producers and pipeline companies on gas sales contracts.

Northwest says it may be mid-1979 or later before these negotiations are completed and gas sales contracts are signed.

"In general, we would expect that final producer contracts cannot be obtained in less than 6 months following Congressional resolution of various pricing issues and perhaps not even then if the very important question of cost responsibility for processing Alaskan gas has not been settled by the FERC," Alaskan Northwest said in response to questions posed by Legislative Affairs on behalf of the interim committee studying a proposed $500 million equity investment by the state in the project.

The question of who should build and pay for the necessary conditioning facilities is one of the major issues that must be resolved before work can proceed on the Alaska Highway natural gas pipeline. These costs apparently will be borne either by the North Slope oil producers, or by the companies in the Alaskan Northwest pipeline consortium, or some combination of them.

It now appears the producers and pipeline companies will negotiate responsibility for the conditioning facilities at the same time they negotiate a sales price for the gas, but any agreement reached in

---

[1] For a detailed discussion of the natural gas bill and its effects on Alaska, see "The Politics of Gas," by Steve Cowper, Alaska Advocate, October 19-25, 1978.

negotiations will be subject to FERC approval. It is possible, however, that FERC will hold a proceeding and settle the conditioning issue before the contract negotiations begin. Whatever procedure is followed, FERC will have to determine which costs are attributable to "production," which are the responsibility of the producers, and which to "transportation," which are the responsibility of the pipeline companies. If the conditioning plant were built by the pipeline companies, it would be regulated by FERC and its costs included in the pipeline tariff. If it were built by the producers, it would not be subject to FERC regulation.

Neither the producers nor the pipeline companies are eager to accept responsibility for the conditioning facilities. The producers have argued that if they must build the conditioning facilities, they might decide the investment at this time is not worth the gains to be made from gas sales. On the other hand, Northwest has argued that it may have difficulty raising enough money to pay for both the pipeline and the conditioning facilities.

FERC REPORT FAVORS 1260-psig PRESSURE FOR GAS PIPELINE

A report issued recently by the Alaska Gas Project Office of the Federal Energy Regulatory Commission favors a 1260-psig operating pressure for the northern sections of the Alaska Highway gas pipeline.

In preparing its report to FERC on the options for operating pressure, the Alaska Gas Project Office (AGPO) held discussions with the major interested parties, including the State of Alaska, Sohio, ARCO, Exxon and Alaskan Northwest Pipeline Company. The AGPO said its report does not represent an official FERC finding but is "an effort to illuminate the choice of maximum allowable operating pressure."

The Canadian National Energy Board (NEB) already has selected a 56-inch diameter, 1080-psig system for the sections of the pipeline south of Whitehorse, Yukon Territory. The Canadian decision, the AGPO said, had the effect of narrowing the options for the 48-inch segments north of Whitehorse to these: (1) the 1260-psig system proposed by Alaskan Northwest; (2) the 1680-psig system favored by two of the three principal North Slope gas producers (Exxon and ARCO); and (3) an intermediate design which would operate at 1440 psig.

Generally, the higher pressure systems can carry more Natural Gas Liquids (NGLs) than the lower pressure systems, and the higher pressures can move a greater volume of gas. The higher pressure systems cost more, but would be able to deliver gas cheaper (lower cost-of-service) at higher through-put levels than currently envisioned for the Alaska Highway project.

Alaskan Northwest told the AGPO it opposes the higher pressure alternatives. "A major source of concern is their belief that a delay of up to two years could result from choosing the higher pressure system due to a need for extensive testing of the various components of such a system," the report says. "A delay of up to two years is estimated by the project sponsors to result in additional carrying charges of up to $1 billion."

Alaskan Northwest showed a cost-of-service advantage for the lower pressure system at the through-put volumes they expect (between 2 and 2.4 billion cubic feet a day). The higher pressure alternative does not become superior in performance until the through-put rate passes 3.8 billion cubic feet a day, according to Alaskan Northwest's figures.

The AGPO said it believes that the President's Decision on the Alaska Natural Gas Transportation System "creates a predisposition that the 1260-psig system is the one authorized by the President and the Congress."

Before FERC should agree to a higher operating pressure than 1260-psig, the report says, it should get concurrence of the Canadian government, which has expressed "severe reservations" about the safety and reliability of the 1680-psig alternative.

FERC also should make sure that consumers would benefit from a decision to use a higher pressure system, the report says.

Finally, FERC should not select a higher pressure system if it would undermine the project sponsors' ability to secure private financing, the AGPO says.

Comments to FERC on the report are due November 15.

GAS CONDITIONING FACILITIES TO COST ABOUT $2 BILLION

Conditioning facilities necessary to prepare North Slope gas for pipeline shipment likely will cost about $2 billion, according to a voluminous study conducted for 11 pipeline companies and seven North Slope oil producers.

The seven-volume study, which has been in preparation since the summer of 1977, sets out a preliminary design for the conditioning facilities, a timetable for startup in the summer of 1983 (now acknowledged to be impossible to meet), implementation plans and cost estimates. The study was released to state officials in early October.

The study cost $1.4 million and was prepared for the 18 companies by the Ralph M. Parsons Company of Pasadena, Calif., an engineering construction firm. The companies conducting the study have kept some of the information proprietary, and they plan to sell it to the firms that ultimately build the conditioning facilities.

Conditioning the gas for shipment includes removing carbon dioxide and the heavier Natural Gas Liquids, and then compressing and chilling the gas to pipeline specifications.

The Parsons study makes a number of assumptions about the pipeline, including:

- Production of 2.6 to 2.8 billion cubic feet a day of raw gas, which would yield pipeline quality gas for shipment of 2 billion cubic feet a day (after field and local fuel gas demands and shrinkage from conditioning). The President's Decision anticipates pipeline through-put of 2.4 bcf/day.

- Pipeline pressure of 1440 psig. (The President's Decision anticipates pressure of 1260 psig.)

- Most of the Natural Gas Liquids will be shipped through the gas pipeline. Under the plan set out in the Parsons study, all of the ethane (C^2), all of the propane (C^3), and some of the butane (C^4) could physically be placed in the gas pipeline. The remainder of the butane and all of the pentane (C^5) would be shipped south in the Trans-Alaska oil pipeline.

If completed by 1983, the study says, the conditioning facilities would cost about $2 billion in escalated dollars (assuming inflation of 6.73 percent a year), with an accuracy of plus or minus 20 percent. Each year of delay would increase the cost about 9 percent, the study says.

DEPARTMENT OF NATURAL RESOURCES SELECTS FIRM TO PROMOTE PETROCHEMICALS

Bonner & Moore Associates, Inc., of Houston, Texas, has been awarded a $70,000 contract to help the state promote development of a petrochemical industry based on royalty gas and gas liquids.

Natural Resources Commissioner Robert LeResche said he intends to select a steering council of people from Fairbanks, Valdez, Haines, Anchorage, Kenai and perhaps other locations to assist Joe F. Moore, president of the consulting firm, and the Alaska Royalty Oil and Gas Development Advisory Board, in planning the development.

Once the steering council is established, LeResche said, "Joe Moore's job would be to put together the type of development that the council feels would be most beneficial, and to find a firm that would be willing to contract to buy the (royalty) gas and undertake the development. In this way we will be able to give potential purchasers a specific development that we want to see happen..."

Moore also will update a study he conducted last year for the Department of Revenue, which assessed the economic feasibility of gas-based petrochemical development in Alaska, transportation schemes, markets and other related issues. That study concluded that petrochemical manufacturing based on ethane and heavier NGLs is economical in Alaska at a wellhead gas price of about $1.24 per million Btus. However, that study was criticized by oil company representatives and others because it underestimated the costs of construction. LeResche said Moore's update study will use a more realistic "construction cost multiplier," which compares construction costs in Alaska with costs on the Texas Gulf Coast.

Before the state should enter into a contract selling the royalty gas, LeResche said, several factors outside the state's control need to be resolved. These include execution of gas sale contracts between the North Slope producers and the pipeline companies, and determinations by FERC on the size and pressure of the pipeline and specifics of the conditioning facilities (which will affect composition of the royalty gas).

CANADIAN DECISIONS ON GAS EXPORTS WILL AFFECT ALASKA HIGHWAY PIPELINE

Published reports[1] indicate that the outcome of Canadian National Energy Board gas supply-demand hearings, which began October 11, could affect the success of the Alaska Highway pipeline project.

Alberta gas producers are pushing the Canadian government to allow long-term gas exports to the United States, and they are pointing to substantial new gas discoveries in Canada's Deep Basin as justification.

"If the new reserves prove to be substantial, and if the Canadian government approves their long-term sale to the U. S., the gas could be transported much more cheaply by expanding existing pipelines than by building the costly new pipeline network to Alaska," Business Week reported recently.

The magazine quotes Canadian Hunter Exploration Ltd., the leading exploration company in the Deep Basin, as saying the area stretching from west-central Alberta north into British Columbia could contain 50 trillion cubic feet of natural gas, or nearly twice the proven reserves at Prudhoe Bay. Other estimates place the level of gas reserves at about 10 trillion cubic feet.

The Oil and Gas Journal said in its September 18 edition that "strong geological evidence points to the probable existence of an enormous gas accumulation trapped in the deepest part of the Alberta syncline and its extension into British Columbia... Reserve potential is so large as to alter significantly the energy supply estimates for North America."

The NEB must decide (subject to approval of the Canadian cabinet) whether to grant permission for increased gas exports into the United States. If it does give permission for massive, long-term sales (U. S. sales already account for more than 40 percent of Canadian gas sales), it will mark a dramatic turnaround in government energy export policy.

---

[1] Business Week, Sept. 25, 1978; The Oil and Gas Journal, Sept. 18, 1978; The Financial Post (a Canadian publication), June 10, 1978; Energy User News, Oct. 2, 1978.

Since 1970, Canada has approved export licenses for only one year, provided the gas was surplus to Canadian requirements and the price was just and reasonable. The Alberta producers will be trying to convince the NEB that they have enough surplus gas to serve Canada as well as enough to export south for longer than one year.

The largest export applicant is PanAlberta Gas Co., Ltd., a subsidiary of Alberta Gas Trunk Line (AGTL). AGTL is part owner of Foothills Pipe Lines, which will build the Canadian sections of the Alaska Highway gas pipeline. PanAlberta already has signed tentative contracts with Northwest Alaskan Pipeline Company to export just over a billion cubic feet a day of gas for six years. Approval of this proposal would boost the entire Alaska Highway project, since such a vast amount of gas would require pre-building of the southern section of the pipeline. Pre-building has been promoted as a way to ease financing of the entire project.

A group of Alberta natural gas producers, called the "ProGas" consortium, has applied for government approval to export 500 million cubic feet a day to the Midwest through existing TransCanada pipelines for a five-year period. Approval of this rival proposal could be detrimental to the Alaska Highway pipeline, since it might preclude the need for the pre-built southern section.

BEAUFORT SEA SALE FACES OBSTACLES

A number of environmental, administrative, legal and economic problems make it uncertain whether the proposed Beaufort Sea offshore lease sale will take place in December of 1979 as planned.

This major offshore sale of more than half a million acres is being planned jointly by the state and the federal government, an unprecedented arrangement. It will be the state's first North Slope sale in more than a decade.

The Beaufort Sea is considered one of the most promising areas in the United States for finding new accumulations of oil and gas. Geologists estimate the offshore area may contain 2.7 billion barrels of recoverable oil and 13.5 trillion cubic feet of recoverable natural gas.

"The Beaufort Sea sale has more things going against it than for it right now," says Tom Cook, director of the Division of Minerals and Energy Management. "I expect to see a good deal of environmental opposition, and I'm sure there will be opposition from some quarters of the Native community. The objections they raised about the Point Thomson sale are a preview of what you'll see when the Beaufort is addressed in public forums."

Governor Hammond cancelled the Point Thomson North Slope sale in September, citing the federal government's failure to deal with the West Coast oil surplus, objections from local residents and the oil industry, lack of environmental data and a dispute with the Interior Department over title to the lands. The Point Thomson acreage is near two Exxon discoveries, and the state wanted to preclude "drainage" from under the unleased acreage. (It is unlikely this would occur in the near future, however, since Exxon has not announced plans for producing its discoveries.)

Environmental problems with the sale are likely to center on the bowhead whale, an endangered species, whose habitat and safety are protected under the federal Endangered Species Act of 1973. Very little research has been done on the bowhead's feeding, mating and migration patterns, so it is unclear whether the whales would be affected by development of the proposed sale area.

Protection of the bowhead is the responsibility of the National Marine Fisheries Service (NMFS) in the U. S. Department of Commerce, which can object to the sale if it determines there would be an adverse effect on the bowhead's safety or habitat.

Other environmental problems include professional disagreement over the safety and adequacy of available Arctic oil development technologies, particularly the industry's ability to prevent, contain and clean up oil spills.

The federal Bureau of Land Management's Outer Continental Shelf (OCS) office in Anchorage has contracted for two studies on the bowhead and environmental effects of the proposed sale, one to be conducted by the Alaska Whaling Commission and the other by the Naval Arctic Research Laboratory in Barrow. The results of these studies will be turned over to the NMFS, which will advise the Secretary of the Interior on whether a sale would be detrimental to the bowhead.

Bob Brock, assistant manager of the OCS office, said the secretary could decide to proceed with the sale whatever the NMFS decided, but "a jeopardy ruling (from NMFS) definitely would be a big obstacle."

Another category of obstacles involves the monumental task of reconciling and meshing different state and federal leasing laws and regulations.

The Beaufort Sea "Memorandum of Understanding" signed last March by Governor Hammond and Interior Secretary Andrus says the state and federal governments will develop compatible procedures for conducting the sale. This may involve, among many other things, adoption of a common lease form so that it will make no difference to bidders whether the land is owned by the state or federal government.

Of the offshore area proposed for sale, 68 percent belongs to the state, 13 percent belongs to the federal government, and 19 percent is disputed. Some staffers predict that the state and federal government eventually will end up in court over ownership of the disputed 19 percent.

The Department of Natural Resources currently is drafting new leasing procedures, a process that has been in motion since mid-1977. Most of the work was done, however, before passage of the new leasing law (HB 854) by the last legislature. Revised leasing procedures should be completed soon and may go to public hearings by the end of the year.

The procedures will formally establish an Alaska Advisory Committee on Leasing, composed of representatives of various state agencies and local governments, which will advise the commissioner of Natural Resources on proposed sales. This group has been operating on an ad hoc basis for about a year.

The new procedures also will mandate that a Social, Economic and Environmental Analysis (SEEA) be prepared by the state for each proposed sale. The Beaufort Sea SEEA is expected to be completed by March or April, and public hearings will follow.

Another potential problem is Public Land Order 82, an executive World War II action that reserved all submerged lands north of the Brooks Range crest for military purposes. The order was revoked in 1960, but Interior officials have argued that since it was in effect at the time of statehood, the state did not automatically get title to the lands.

The state is currently involved in what are described as "extremely delicate" negotiations with Interior on this issue. State officials believe the state's case on P.L.O. 82 is very strong, but they say they have refrained from discussing it publicly so as not to back Interior into a corner.

The ramifications of this issue for the state and the North Slope producers are staggering, since the land in question includes some of the state's greatest proven and potential resources, including about 40 percent of the oil and gas at Prudhoe Bay and the entire Arctic coastline out to the three-mile limit.

Another potential obstacle to the Beaufort Sea sale is resolution of the West Coast oil surplus. Some say it makes no sense for the state to proceed with additional leasing as long as the economic return on the resource is so low, and it is conceivable the state might cancel the sale if the federal government failed to take action to resolve the surplus.

STATE WILL SEEK PERMISSION TO EXPORT ROYALTY OIL TO JAPAN

Natural Resources Commissioner Robert LeResche says he will visit Japan in November to lay the groundwork for a short-term sale of the state's Prudhoe Bay royalty oil to a Japanese refiner.

The sale envisioned by LeResche would be structured as an exchange, with a refiner on the U. S. East Coast receiving an equivalent amount of foreign oil that would have gone to the Japanese refiner.

The state has been urging federal energy officials to allow the export or exchange of Alaska oil as a solution to the West Coast oil surplus. Since transportation costs would be lower if Alaska oil were moved directly to Japan instead of through the Panama Canal to the U. S. Gulf and East coasts, the wellhead price would be higher and the state's revenue from royalty and severance tax payments would increase.

The export of crude oil is now restricted by three federal laws with similar provisions. The most restrictive--1977 amendments to the Export Administration Act--allows exports of oil carried through a pipeline that crosses federal lands only if the President makes specific findings that the exports in question:

- will not diminish the total quantity or quality of crude oil available to the United States;

- will have a positive effect on consumer oil prices by decreasing the average crude oil acquisition costs for refiners;

- will be made only pursuant to contracts which may be terminated if the petroleum supplies of the United States are interrupted or seriously threatened;

- are in the national interest.

Either house of Congress could veto the proposed export.

The Japanese exchange under consideration by the state would be structured to meet those legal requirements. State officials view the royalty oil swap proposal as a way to lay the question directly on the desk of President Carter, who thus far has been reluctant to tangle with Congress, particularly the House of Representatives, on the issue.

If permission to exchange the royalty oil were granted by Carter and Congress, state officials believe it would be a "foot in the door" for the export of the producers' North Slope oil and would serve to diffuse political opposition to exports. When the question is considered in the national forum, the reasoning goes, it is advantageous to center debate on the least objectionable proposal possible: exchange of royalty oil (rather than producer oil) for non-Arab oil delivered to the U. S. East Coast.

LeResche's November trip also will take him to Mexico, which he says "looks like a real good potential third partner (to deliver oil to the U. S. East Coast) for the deal."

The legislature last session amended the state statute that requires legislative approval for the sale, exchange or disposition of royalty oil and gave the administration authority to make a one-year sale without legislative approval to relieve market conditions.

LeResche said he hopes to have the Japanese exchange worked out and ready for presentation to Carter early next year.

STATE CONSIDERS FOOTHILLS OIL PIPELINE PROPOSALS

Eight state departments are now analyzing proposals by a Canadian pipeline consortium to build a new oil pipeline from Skagway to existing pipelines in Alberta, or from Delta Junction down the Alaska Highway gas pipeline corridor. One commissioner is already on record opposing the proposals.

Foothills Oil Pipe Line Ltd., jointly owned by Alberta Gas Trunk Line and Westcoast Transmission, recently proposed the new oil pipelines as a way to move Alaska oil to inland U. S. markets. This is the same group of companies that will build the Canadian sections of the Alaska Highway gas pipeline.

The analysis, which is being coordinated by the Division of Policy Development and Planning, will examine economic feasibility, effect on state revenues, environmental impacts, impacts on communities, effect on the state's economy, and public sentiment toward the proposals, among other things. Responses from the participating departments--Revenue, Natural Resources, Environmental Conservation, Fish and Game, Transportation and Public Facilities, Community and Regional Affairs, Commerce and Economic Development, and Labor--are due November 17.

Foothills officials will be invited to respond in December to questions and problems identified by the departments. The state then hopes to take a formal position by the end of the year.

Revenue Commissioner Sterling Gallagher says he thinks the state should oppose the Foothills oil pipeline because its tariff will be too high to result in an $8 to $9 wellhead price. Gallagher says an $8 to $9 wellhead is needed before the oil companies will develop economically marginal North Slope fields such as Kuparuk and Lisburne.

"If we allow pipelines to be built that yield us only a $4 to $5 wellhead value, there will be economic pressure to keep that line full. We could keep those lines full for the next few years with Prudhoe Bay production, but in the long run, it would actually lower our return from the main Prudhoe Bay field and kill the incentive to develop smaller fields in Alaska," Gallagher said recently in a letter to the governor.

"I feel for the long-term development interest of Alaska, we should oppose all transportation alternatives which will not yield a sufficient incentive to obtain additional production from Prudhoe Bay, as well as other marginal fields in Alaska," Gallagher said.

In a presentation to state officials in September, Foothills officials asked for the state's opinion of the proposals and said they hoped to get a "consensus" before proceeding. Foothills has not yet filed a formal application with the Secretary of the Interior, although it will have to do so soon under terms of a new Crude Oil Transportation Systems law passed just before Congress adjourned. (See next item.)

Ed Phillips, senior vice president of Foothills Oil Pipe Line Ltd., said his firm will meet in November with representatives of Sohio and Ashland oil companies to see whether they will support the Foothills proposal.

"We have to have someone who says they'll put oil through our line" before we can move ahead, Phillips said. "If Sohio and Ashland turn us down, we'd have to do some fast scrambling. If they refused it would be a major setback."

Phillips said Foothills recently completed a reevaluation of the costs of building the Skagway-to-Whitehorse route, which showed a netback wellhead of about $3. "That's more than the state is getting now for the oil that is going to the Gulf Coast," he said. The Big Delta route would offer a higher netback to the state and also would be more attractive to environmentalists, he said. However, the Big Delta route would leave the southern portions of TAPS underutilized, and Sohio would have to pay the full TAPS tariff to Valdez, even if the oil were diverted to a new line near Fairbanks.

"If the state could indicate that there would be a significant increase in production from Prudhoe Bay," Phillips said, then the Big Delta route would be very attractive.

It is likely Foothills will have to make a decision on whether to proceed before the state completes its analysis, he said. "If we just get some encouragement from Sohio and Ashland, we'll be ready to go ahead."

CONGRESS APPROVES PROCEDURE FOR SELECTING WEST-TO-EAST OIL PIPELINES

Congress has established a procedure for Presidential selection of west-to-east crude oil pipelines in an attempt to solve both the West Coast surplus and a "serious shortage" of oil in the northern tier states.

The new "Crude Oil Transportation Systems" law is part of the Public Utility Regulatory Policies Act, one section of President Carter's energy package.

Declaring that "expeditious Federal and State decisions for west-to-east crude oil delivery systems are of the utmost priority," Congress set up a procedure for review of pipeline alternatives by federal agencies, which will make recommendations to the President.

In order to be eligible for consideration, applications for proposed pipelines must be filed with the Secretary of the Interior within 30 days after the bill is signed by the President. The secretary may accept proposals for an additional 60 days if he determines they are in the national interest.

The bill states that final Environmental Impact Statements on accepted applications must be completed by December 1, 1978. The President will have 45 days (subject to a 60-day extension, if necessary) after receiving comments and recommendations to decide which, if any, of the proposed pipelines will be approved.

Once a pipeline is selected, the new law provides an expedited procedure for action on all federal permits, licenses and approvals required for construction and operation of the system. The law also mandates expedited federal authorizations on the proposed Sohio pipeline from Long Beach to Midland, Texas, although all federal authorizations for this project already have been granted.

The Sohio pipeline, however, still must get air quality permits from the California South Coast Air Quality Management District Board, a process that could take another year. The board has not yet approved Sohio's plan to offset the air pollution from its project by installing a $78 million scrubber on a Southern California Edison power plant.

In addition, city of Long Beach voters will decide November 7 whether land owned by the city should be leased to Sohio for the project's terminal. A rejection by Long Beach voters would delay the project at least a year, when the issue could be placed on the ballot again. Sohio lobbyist Ken Showalter said the company might consider moving the port terminal to Los Angeles harbor in the event the Long Beach referendum fails.

A number of other proposed west-to-east pipelines have been under consideration for years but have faced numerous environmental and regulatory obstacles.

The Kitimat pipeline project, which would require new construction from a terminal at Kitimat, British Columbia, to Edmonton, Alberta, and use existing pipelines from Edmonton into the Midwest, was essentially killed when the Canadian National Energy Board decided recently that the country does not need oil importing facilities on its west coast.

Reversal of the existing Trans-Mountain pipeline between Cherry Point, Washington, and Edmonton was precluded by an amendment to federal law that prohibits expansion or building of any new oil docks east of Port Angeles, Washington.

The Northern Tier pipeline project, which would run a new pipeline from Port Angeles to Clearbrook, Minnesota, recently got approval from Washington State after a long series of regulatory hearings. However, Clallam County, which would be host for the oil port, has challenged in court the state's right to preempt local land-use ordinances. If the court were to rule against the state, it could kill the project by precluding construction of a tank farm in Clallam County, according to Associated Press reports.

Passage of the "Crude Oil Transportation Systems" law is an expression of Congress' desire to bring about construction of a west-to-east pipeline to serve the crude-short northern tier states of Washington, Oregon, Idaho, Montana, North Dakota, Minnesota, Michigan, Wisconsin, Illinois, Indiana and Ohio. These states used to depend heavily on oil imported from Canada, which averaged about 1.2 million barrels a day in 1973.

The Arab oil embargo brought a drastic change in Canadian export policy, and the government had planned to phase out oil exports completely by the early 1980s in order to conserve oil for its own use. Canada now exports about 180,000 barrels a day to the northern tier states, and originally had planned to cut exports by 20,000 barrels a day in 1979 and down to 1,000 barrels a day in 1980.

However, because of a lower-than-expected demand and a brighter supply picture, the NEB recently decided that light oil exports (now 55,000 barrels a day) would be continued at the current level for three years and cease in 1981 except in exchange arrangements. Exports of heavy oil will be allowed to continue without restriction, as is current policy, as long as Canadian requirements are met first.

PETROLEUM REVENUES FALL BELOW PRE-PRODUCTION EXPECTATIONS

The West Coast oil surplus and higher-than-expected pipeline tariffs and tanker transportation charges have substantially reduced the state's petroleum revenues from levels predicted a year and a half ago.

The declining trend of estimates for the current fiscal year are shown below.

Estimates of FY 79
Petroleum Royalty and Severance Tax Revenues
(millions of dollars)

	Royalties*	Severance Tax	Total
LAA-Research Forecast			
March 1977			657.1
May 1977			634.0
Dept. of Revenue Forecast			
June 1977	520.9	207.7	727.1
January 1978	358.0	176.0	534.0
LAA-Research Forecast			
June 1978			437.4
Dept. of Revenue Forecast			
September 1978	273.2	160.5	433.7

* Royalty amounts are gross figures without deductions for permanent fund contributions (25%), renewable resources fund contributions (5%) or native claim settlement payments (16% of royalty; or 2% of total gross value). Not included in these figures are oil and gas property tax or income tax revenues.

The 1977 estimates made prior to actual production were based on the expectation that wellhead values would be about $7.50. In fact, the wellhead price has never been this high; it has ranged from a high of $6.23 in August of 1977 to a low of $4.23 in May of 1978. The average wellhead price currently is about $4.40.[1]

Deputy Revenue Commissioner John Messenger says a $7.50 wellhead was not an unreasonable expectation, since "the oil companies themselves, as well as numerous other third party experts, were projecting wellhead values in the $7 to $8 range" in early 1977.

Declining oil revenues can be attributed to four major factors:

Pipeline tariffs -- In June 1977 the eight oil companies that own TAPS filed initial tariffs with the Interstate Commerce Commission (now FERC) ranging from $6.04 per barrel to $6.44 per barrel. The average was about $6.20 per barrel. The State of Alaska, the U. S. Department of Justice, the ICC's Bureau of Investigations and Enforcement and the Arctic Slope Regional Corporation filed objections, claiming the tariffs were too high.

---

[1] The table attached as an appendix to this report, which was prepared by Al Latham, shows a month-by-month breakdown of Prudhoe Bay oil destinations and prices.

After considering the protests, the ICC decided the high initial tariffs were not in the public interest and ordered them suspended. The ICC instituted "interim" tariffs averaging about $4.84 per barrel, which were to be in force for seven months while it considered various substantive issues.

Several of the oil companies then brought suit against the ICC, claiming it had no authority to deny the carrier's initial filings. The U. S. Supreme Court allowed the owner companies to reinstate their initial tariffs for a period, but on June 6, 1978, the high court upheld FERC's authority to suspend the initial tariffs and set interim tariffs instead. The state got a retroactive payment of about $17 million for royalty and severance taxes as a result of this decision. However, since the commission's "interim" tariff order was only in effect for a seven-month period, which expired February 28, 1978, the average company tariff of about $6.20 has been in effect for some time and will remain in effect until FERC rules on the tariff case.

The issue is being considered in two phases. Phase I involves general issues of methodology, such as the proper method of calculating the rate of return. A FERC administrative law judge will continue to take testimony on Phase I until late January. Thirty-seven rebuttal witnesses for the oil companies will begin testifying the first week in November.

The judge is expected to make a decision, or perhaps a recommendation to FERC, sometime next spring. If the judge decides the case, his decision could be appealed to the full commission. Whatever procedure is used, the losing side can (and probably will) appeal FERC's decision to the federal courts. Attorneys for the state say they expect FERC to make its decision on Phase I by June, 1979.

If the state gets a favorable ruling on Phase I, the tariff could be reduced by several dollars, state attorneys say.

The main issue in Phase II involves the costs of constructing the pipeline. FERC will determine which costs were reasonable and prudent and should be included in the rate base, and which were not reasonable and should be excluded. Hearings on Phase II probably won't begin before next summer, and it is likely to be several years before the tariff issue is finally resolved.

Field charges -- State royalty payments (one-eighth of production) are based on the wellhead value of the oil. The state claims these payments should be based on the value of the oil as it enters the Trans-Alaska pipeline. The oil companies claim the royalty payments should be based on the value of the oil as it comes out of the ground, and that the state should pay some or all of the "field charges" or "upstream costs." These charges range from 52¢ to $1.11 per barrel, depending on the company, and currently are being deducted from the state's royalty payments.

In October, 1977, the state filed suit against the companies, claiming that royalty payments were being calculated incorrectly. The issue is being litigated in two stages. The first question to be settled is whether the oil companies can properly deduct field charges from the royalty payments.

Oral arguments on the first part of the case were delayed because state Superior Court Judge Allen Compton suffered a heart attack in August. Compton recently returned to the bench on a part-time basis, and oral arguments are now scheduled for December 11.

Tanker transportation costs -- In computing the wellhead value of the oil, the companies take the destination sales price and then subtract the pipeline tariff, the field charges and the tanker charges for moving the oil from Valdez to the West and Gulf coasts.

The companies have been claiming tanker transportation costs ranging from 81¢ to $1.08 to the West Coast and from $2.75 to $3.64 to the East and Gulf coasts. Before production began, the oil companies and other third party experts projected tanker costs to the West Coast of 50¢ to 70¢ and charges to the Gulf Coast of $2.50 to $2.70.

Whether the tanker charges being claimed by the companies are too high will be litigated in the second part of the royalty suit.

Martingale, Inc., of Cambridge, Massachusetts, currently is conducting a study of tanker transportation charges under a $68,400 contract with the Legislative Affairs Agency and the Department of Revenue. The study is scheduled for completion in December.

West Coast oil surplus -- Because all Prudhoe Bay production cannot be consumed on the West Coast, and cannot be exported, the surplus oil must be shipped at a much higher cost through the Panama Canal to the U. S. Gulf and East coasts. In August, the latest month for which figures are available, 431,000 barrels a day, or 36 percent of total Prudhoe Bay production, went to the Gulf and East coasts.[1]

The extra charges for shipping this oil the longer distance to market directly reduce the wellhead price.

---

[1] Energy Background Report #1, September 28, 1978, incorrectly stated that about 600,000 barrels a day are shipped through the Panama Canal. This figure was supplied by Revenue Commissioner Sterling Gallagher, but subsequent calculations by the Legislative Affairs Research Division indicate that the 431,000 figure is correct.

ALPETCO CONTINUES SEARCH FOR PETROCHEMICAL FACILITY SITE[1]

ALPETCO has narrowed possible sites for its contemplated world scale refinery-petrochemical complex from four to two--Valdez and Kenai (Wildwood)--and anticipates making its final choice known by mid-November.

A Cook Inlet Regional Native Corporation spokesman indicated that ALPETCO is negotiating with the Kenai Native Association to lease the Wildwood site. However, ALPETCO denies that the firm has made a final selection.

ALPETCO is proceeding with the preparation of a Draft Environmental Impact Statement (DEIS). It details the scope of work to be performed by ALPETCO to meet Environmental Protection Agency (EPA) requirements. The scope of work for the DEIS is expected to be adopted before the end of the year after review by the EPA, the Department of Environmental Conservation, other federal and state agencies, and the public.

ALPETCO has continued to meet with representatives of Japanese firms to discuss participation in the project. ALPETCO believes it will be able to obtain satisfactory agreements with refiners and marketers to sell "light ends" of the crude on the West Coast. However, ALPETCO is experiencing difficulty in finding a market for the "heavy ends" produced from Alaska crude. The firm is presently working to develop alternative solutions to this problem.

Additionally, the results of soils investigations conducted previously at the various sites by ALPETCO are now being used to analyze the relative merits of the two remaining sites. ALPETCO has filed a National Pollutant Discharge Elimination System (NPDES) Application for Permit to Discharge Waste Water with the EPA. The company has installed air quality monitoring stations at the Kenai and Valdez sites. Monitoring is being performed by Dames and Moore.

ALPETCO has hired a vice president for operations, Michael B. Carmichael, who formerly worked for Mobil Oil and Exxon. He will be in charge of design and construction, as well as operation of the project.

STATE APPEALS TANKER LAW DECISION

The state has asked the Ninth U. S. Circuit Court of Appeals to overturn a lower court decision that invalidated major portions of the state tanker regulation law enacted in 1976.

U. S. District Judge James M. Fitzgerald, drawing on a recent U. S. Supreme Court decision, ruled June 30 that the federal government has exclusive jurisdiction in regulating tanker equipment and design features

---

[1]Contributed by Elke Kallab.

under the Ports and Waterways Safety Act of 1972. Therefore, Alaska cannot charge oil tankers "risk avoidance" fees based on state-imposed design and construction standards, the judge ruled.

The judge also ruled that the Coastal Protection Fund is a dedicated fund, which is prohibited by the Alaska Constitution.

Fitzgerald said his decision had nothing to do with whether Alaska may or should have a Coastal Protection Fund providing a ready source of money to clean up oil spills and abate pollution, since other states have created funds for that purpose which have been upheld. The only question, the judge said, is "whether the means chosen by the state to accomplish its purposes are in accord with federal and state constitutional provisions."

The suit, filed by North Slope and Cook Inlet oil producers (Chevron, ARCO, Exxon, Mobil, Union Oil of California) and companies operating tanker fleets in the Alaska trade (Gulf Oil, International Ocean Transport, Keystone Shipping), sought to declare the Alaska tanker law unconstitutional and prevent its enforcement.

The Alaska law regulates tanker vessel traffic, transfer of crude oil and refined petroleum products, oil terminal facilities and marine carriers, through a licensing system of risk avoidance certificates. Its stated purpose is to decrease the likelihood of oil spills in Alaska waters by requiring tankers carrying oil to be equipped with certain safety and maneuvering capability features, and, if they don't have these features, to be escorted by tugs while navigating in the coastal waters of the state.

To navigate in state waters, tankers must acquire certificates of risk avoidance, which are conditioned on proof of financial responsibility and payment of an annual risk charge. The risk charges (along with other damages, penalties and fees) go into the Coastal Protection Fund. The amount of the risk charge depends on the presence or absence of safety equipment and design features.

The U. S. Supreme Court last March ruled unconstitutional part of a Washington state tanker law requiring certain design features on tankers entering Puget Sound (Ray V. ARCO). The high court held that Congress had entrusted the Coast Guard with the duty of determining which tankers are sufficiently safe, and that states are foreclosed from imposing different or more stringent design and construction regulations.

Other issues in the Alaska suit are scheduled for trial in December. These include whether the state can prohibit ballast discharge into state waters, whether the state can board tankers for inspection without a warrant, whether the state can require operating certificates, and whether the state can revoke operating certificates without due process.

OPEC MAY RAISE OIL PRICES

The Organization of Petroleum Exporting Countries (OPEC) is expected to hike the price of oil by 5 to 15 percent at its meeting in Abu Dhabi in December, press reports indicate.

Former Saudi Arabian oil minister Sheikh Abdullah Turaiki has been quoted as saying the increase might be as high as 30 percent, but most consider this unlikely.

Kuwait's Sheik Ali Khalifah, currently OPEC's president, has said he will recommend a 10 percent increase, while Saudi Arabia, the cartel's largest producer, has suggested that a 5 percent increase would be reasonable.

Oil prices have not been rising as rapidly as inflation, and have not been raised substantially since the four-fold increase in early 1974.

An increase in OPEC prices would mean higher prices for Alaska oil, since under the federal government's complicated pricing and entitlements structure, Alaska oil receives the imported price.

CONGRESS APPROVES STOCK OWNERSHIP PLAN

Congress has approved, and President Carter says he will sign into law, a far-reaching change in the tax law that allows states to establish private corporations for the benefit of their citizens.

The new law, pushed through Congress by Alaska Senator Mike Gravel, authorizes formation by states of General Stock Ownership Corporations (GSOC). The plan has been hailed by its sponsors as a grand experiment in economic democracy, a way to distribute the state's resource wealth to all citizens.

The GSOC, if it meets certain statutory requirements, will not be subject to federal income tax. Instead, shareholders of the GSOC will be taxed on their daily pro rata shares of the GSOC's taxable income.

All residents of a state which charters a GSOC are eligible to become shareholders in the corporation and are entitled to a stock interest in the corporation (provided they are residents at the time of chartering and remain residents until stock is issued). At least 90 percent of the income of the GSOC which is not used to pay corporate operating expenses must be distributed to the shareholders each year.

Shareholders would not be able to sell their GSOC stock for five years after acquiring it, and no one individual could purchase or otherwise acquire more than 10 shares of GSOC stock.

Gravel has suggested that the Alaska GSOC purchase British Petroleum's 15.8 percent share of the Trans-Alaska oil pipeline as its first investment. Other investment possibilities include the gas pipeline and the Alpetco petrochemical-refinery facility, or any other business venture.

The GSOC could get money for investment from private lenders, such as commercial banks, or from grants of money, land or mineral rights from the state. The new law would not permit the use of tax-exempt financing for state loans to the GSOC, but the state presumably could loan money to the GSOC at a subsidized interest rate.

Earnings from the venture would pay off the loans, and the leftover profits would be distributed as dividends to the citizen stockholders.

Gravel, who derived the idea from the economic philosophy of Louis Kelso, predicts the Alaska venture will alter American politics and economics in profound ways, as other states rush to copy the yet-to-be-developed Alaska model. Gravel says the GSOC is an alternative to welfare-state socialism, a way to distribute benefits of corporate capitalism without nationalizing private enterprises and turning over their management to politicians and bureaucrats.

PRUDHOE BAY OIL PRICE AND DESTINATION ANALYSIS
July 1977 through August 1978

Month/Year	Company	Total Production (BBl/m)	Destination Price	Destination	Tanker Costs (dollars)	Pipeline Tariff (dollars)	Field & Other Costs (dollars)	Royalty Wellhead Price (dollars)	Comments
July 1977	ARCO	1,400,000	13.44	W.C.	.88	4.91	.74	6.91	
	EXXON	1,400,000	13.16	W.C.	1.12	5.10	.53	6.41	
	SOHIO	1,900,000	13.37	W.C.	1.10	4.74	.66	6.87	
		200,000	12.53	Valdez	-	4.75	.66	7.12	
		1,600,000	13.42	E & GC	3.83	4.76	.66	4.17	
		23% of total production or 52,000 bbl/day to East and Gulf Coast						5.94 av.	
August 1977	ARCO	3,100,000	13.44	W.C.	.88	4.91	.74	6.91	5% increase in average wellhead price.
	EXXON	3,000,000	13.16	W.C.	1.11	5.10	.53	6.42	a. Attributable to an 18-fold increase in Alaskan sales.
		74,000	12.30	Valdez	-	5.10	.53	6.67	
	SOHIO	900,000	13.37	W.C.	1.10	4.74	.66	6.87	
		3,800,000	12.53	Valdez	-	4.75	.66	7.12	
		3,400,000	13.42	E & GC	3.83	4.76	.66	4.17	
		23% of total production or 113,000 bbl/day to East & Gulf Coast						6.23 av.	

W.C. = West Coast
E & GC = East and Gulf Coasts
PS 1 = Pump Station 1

Prepared by:
Legislative Affairs Agency
Research Division
A. R. Latham
20 October 1978

AGO 532519

PRUDHOE BAY OIL PRICE AND DESTINATION ANALYSIS
July 1977 through August 1978

Month/Year	Company	Total Production (BBl/m)	Destination Price	Destination	Tanker Costs (dollars)	Pipeline Tariff (dollars)	Field & Other Costs (dollars)	Royalty Wellhead Price (dollars)	Comments
Sept. 1977	ARCO	4,300,000	13.44	W.C.	.88	4.91	.74	6.91	1% decrease over previous month in average wellhead price.
	EXXON	4,200,000	13.16	W.C.	1.15	5.10	.53	6.38	a. Attributable to a 98% decrease in Alaskan sales and a 1% increase in East and Gulf Coast sales.
		87,000	12.30	Valdez	-	5.10	.53	6.67	
	SOHIO	4,200,000	13.37	W.C.	1.11	4.75	.66	6.85	
		2,200,000	12.50	W.C.	-	4.77	.66	7.07	
		5,000,000	13.44	E & GC	3.83	4.75	.66	4.20	
		24% of total production or 165,000 bbl/day to East and Gulf Coast						6.17 av.	
Oct. 1977	ARCO	4,400,000	13.44	W.C.	.88	4.91 6.04	.76	6.46	8% decrease over previous month in average wellhead price.
	EXXON	4,200,000	13.16	W.C.	1.08	6.06	.53	5.49	a. Attributable to an approximately 25% increase in pipeline tariff at mid-month.
		200,000	12.30	Valdez	-	5.53	.53	6.24	
	SOHIO	5,400,000	13.30	W.C.	.92	5.22	.66	6.50	b. Exacerbated by a 39% decrease in Alaskan sales.
		1,200,000	12.52	Valdez	-	5.70	.66	6.16	
		5,100,000	13.42	E & GC	3.32	5.36	.66	4.08	
		23% of total production or 166,000 bbl/day to East & Gulf Coast						5.69 av.	

W.C. = West Coast
E & GC = East and Gulf Coasts
PS 1 = Pump Station 1

Prepared by:
Legislative Affairs Agency
Research Division
A. R. Latham
20 October 1978

AGO 532520

PRUDHOE BAY OIL PRICE AND DESTINATION ANALYSIS
July 1977 through August 1978

Month/Year	Company	Total Production (BBl/m)	Destination Price	Destination	Tanker Costs (dollars)	Pipeline Tariff (dollars)	Field & Other Costs (dollars)	Royalty Wellhead Price (dollars)	Comments
Nov. 1977	ARCO	4,300,000	13.44	W.C.	.88	6.04	.76	5.76	13% decrease over previous month in average wellhead price. a. Attributable to full effect of 25% increase in pipeline tariff. b. Exacerbated by an 11% decrease in Alaskan sales.
	EXXON	4,300,000	13.16	W.C.	1.08	6.27	.53	5.28	
		45,000	12.30	Valdez	-	6.27	.53	5.50	
	SOHIO	5,000,000	13.30	W.C.	.92	6.26	.66	5.46	
		1,200,000	12.50	Valdez	-	6.26	.66	5.58	
		5,100,000	13.40	E & GC	3.31	6.25	.66	3.18	
		24% of total production or 168,000 bbl/day to East & Gulf Coast						4.94 av.	
Dec. 1977	ARCO	4,500,000	13.44	W.C.	.88	6.04	.76	5.76	2% decrease over previous month in average wellhead price. a. Attributable to a 3% increase in East and Gulf Coast sales. b. Moderated by a 40% increase in Alaskan sales.
	EXXON	3,900,000	13.16	W.C.	1.08	6.27	.53	5.28	
		500,000	12.30	Valdez	-	6.27	.67	5.36	
		42,000	12.30	Valdez	-	6.27	.53	5.50	
	SOHIO	4,600,000	13.30	W.C.	.92	6.30	.66	5.42	
		1,200,000	12.53	Valdez	-	6.28	.66	5.59	
		6,100,000	13.41	E & GC	3.32	6.31	.66	3.12	
		27% of total production or 199,000 bbl/day to East & Gulf Coast						4.85 av.	

W.C. = West Coast
E & GC = East and Gulf Coasts
PS 1 = Pump Station 1

Prepared by:
Legislative Affairs Agency
Research Division
A. R. Latham
20 October 1978

AGO 532521

PRUDHOE BAY OIL PRICE AND DESTINATION ANALYSIS
July 1977 through August 1978

Month/Year	Company	Total Production (BBl/m)	Destination Price	Destination	Tanker Costs (dollars)	Pipeline Tariff (dollars)	Field & Other Costs (dollars)	Royalty Wellhead Price (dollars)	Comments
Jan. 1978	ARCO	4,600,000	13.44	W.C.	.88	6.04	.76	5.76	0.3% decrease over previous month in average wellhead price.
	EXXON	3,600,000	13.16	W.C.	1.11	6.27	.53	5.25	a. Attributable to a 4% increase in East & Gulf Coast sales, but almost totally counterbalanced by a 26% increase in Alaskan sales.
		500,000	13.33	W.C.	1.30	6.27	.53	5.23	
		500,000	12.30	Valdez	-	6.27	.53	5.50	
	SOHIO	3,200,000	13.33	W.C.	.99	6.27	.66	5.41	
		1,700,000	12.50	Valdez	-	6.26	.66	5.58	
		7,100,000	13.41	E & GC	3.05	6.27	.66	3.43	
		31% of total production or 234,000 bbl/day to East & Gulf Coast						4.84 av.	
Feb. 1978	ARCO	4,100,000	13.44	W.C.	.88	6.04	.76	5.76	5.2% decrease over previous month in average wellhead price.
	EXXON	3,600,000	13.16	W.C.	1.13	6.27	.53	5.23	a. Attributable to an 11% increase in East & Gulf sales.
		500,000	5.98	PS 1	-	-	.53	5.45	b. Exacerbated by an 18% decrease in Alaskan sales.
	SOHIO	1,000,000	13.36	W.C.	.99	6.27	.66	5.44	
		1,300,000	12.50	Valdez	-	6.26	.66	5.58	
		8,300,000	13.28	E & GC	3.05	6.27	.66	3.30	
		42% of total production or 273,000 bbl/day to East & Gulf Coast						4.59 av.	

W.C. = West Coast
E & GC = East and Gulf Coasts
PS 1 = Pump Station 1

Prepared by:
Legislative Affairs Agency
Research Division
A. R. Latham
20 October 1978

AGO 532522

PRUDHOE BAY OIL PRICE AND DESTINATION ANALYSIS
July 1977 through August 1978

Month/Year	Company	Total Production (BBl/m)	Destination Price	Destination	Tanker Costs (dollars)	Pipeline Tariff (dollars)	Field & Other Costs (dollars)	Royalty Wellhead Price (dollars)	Comments
March 1978	ARCO	6,300,000	13.44	W.C.	.88	6.04	.76	5.76	2.6% decrease over previous month in average wellhead price.
	EXXON	5,600,000	13.16	W.C.	.94	6.27	.71	5.24	a. Attributable to apparent sale price discounting on West Coast and in Alaska by Sohio.
		430,000	5.98	PS 1	-	-	.53	5.45	b. Moderated by 1% decrease in East & Gulf Coast sales and 35% increase in Alaskan sales.
		270,000	13.00	E & GC	3.29	6.27	.64	2.80	
	SOHIO	3,000,000	13.12	W.C.	.99	6.27	.66	5.20	
		2,000,000	12.11	Valdez	-	6.29	.66	5.16	
		11,900,000	13.05	E & GC	3.05	6.27	.66	3.07	
		41% of total production or 399,000 bbl/day to East & Gulf Coast						4.47 av.	
April 1978	ARCO	7,000,000	13.44	W.C.	.88	6.04	.76	5.76	2% decrease over previous month in average wellhead price.
	EXXON	5,200,000	12.83	W.C.	.93	6.27	.72	4.91	a. Attributable to apparent 3%-5% discounting of W.C. sales price by Exxon and Sohio.
		500,000	5.98	PS 1	-	-	.53	5.45	b. Exacerbated by a 38% decrease in Alaskan sales.
		1,300,000	13.00	E & GC	3.33	6.27	.68	2.72	c. Moderated by a 1% decrease in East & Gulf Coast sales.
	SOHIO	5,800,000	12.40	W.C.	.86	6.27	.66	4.61	
		1,000,000	12.50	Valdez	-	6.25	.66	5.59	
		11,500,000	13.01	E & GC	2.78	6.27	.66	3.30	
		40% of total production or 441,000 bbl/day to East & Gulf Coast						4.39 av.	

W.C. = West Coast
E & GC = East and Gulf Coasts
PS 1 = Pump Station 1

Prepared by:
Legislative Affairs Agency
Research Division
A. R. Latham
20 October 1978

AGO 532523

PRUDHOE BAY OIL PRICE AND DESTINATION ANALYSIS
July 1977 through August 1978

Month/Year	Company	Total Production (BBl/m)	Destination Price	Destination	Tanker Costs (dollars)	Pipeline Tariff (dollars)	Field & Other Costs (dollars)	Royalty Wellhead Price (dollars)	Comments
May 1978	ARCO	7,100,000	13.44	W.C.	.88	6.04	.76	5.76	3.6% decrease over previous month in average wellhead price.
	EXXON	5,300,000	12.65	W.C.	1.09	6.27	.53	4.76	a. Attributable to 4% increase in East and Gulf Coast sales and continued apparent sales price discounting on West Coast by Exxon and Sohio.
		500,000	5.98	PS 1	-	-	.53	5.45	
		600,000	12.81	Hawaii	1.32	6.27	.53	4.69	
		700,000	13.00	E & GC	3.64	6.27	.53		
	SOHIO	3,200,000	12.64	W.C.	.86	6.27	.66	4.85	
		1,100,000	11.80	Valdez	-	6.26	.66	4.88	
		14,500,000	13.05	E & GC	3.02	6.27	.66	3.10	b. Moderated by 7% increase in Alaskan sales and new sales in Hawaii.
		44% of total production or 512,000 bbl/day to East & Gulf Coast						4.23 av.	
June 1978	ARCO	7,100,000	13.44	W.C.	.88	6.04	.76	5.76	3.5% increase over previous month in average wellhead price.
	EXXON	4,900,000	12.65	W.C.	1.11	6.27	.53	4.74	a. Attributable to 4% decrease in East & Gulf Coast sales.
		1,100,000	13.18	G.C.	3.35	6.27	.53	3.03	
		700,000	13.41	E.C.	3.64	6.27	.53	2.97	
		400,000	5.54	PS 1	-	-	.53	5.01	
	SOHIO	5,400,000	12.67	W.C.	.86	6.27	.66	4.88	b. Moderated by continuing West Coast and Alaskan discounting and a 13% decrease in Alaskan sales
		1,000,000	11.79	Valdez	-	6.27	.66	4.86	
		12,100,000	13.10	E & GC	2.87	6.27	.66	3.30	
		40% of total production or 465,000 bbl/day to East & Gulf Coast						4.38 av.	

W.C. = West Coast
E & GC = East and Gulf Coasts
PS 1 = Pump Station 1

Prepared by:
Legislative Affairs Agency
Research Division
A. R. Latham
20 October 1978

AGO 532524

PRUDHOE BAY OIL PRICE AND DESTINATION ANALYSIS
July 1977 through August 1978

Month/Year	Company	Total Production (BBl/m)	Destination Price	Destination	Tanker Costs (dollars)	Pipeline Tariff (dollars)	Field & Other Costs (dollars)	Royalty Wellhead Price (dollars)	Comments
July 1978	ARCO	7,300,000	13.41	W.C.	.88	6.04	.76	5.73	4% increase over previous month in average wellhead price.
	EXXON	350,000	5.54	PS 1	-	-	.53	5.01	a. Attributable to a 7% decrease in East & Gulf sales plus an Hawaiian sale and an 18% increase in Alaskan sales.
		6,200,000	12.65	W.C.	1.09	6.27	.53	4.76	
		570,000	12.81	Hawaii	1.31	6.27	.53	4.70	
		110,000	13.18	E & GC	2.93	6.27	.53	3.45	
	SOHIO	6,200,000	12.66	W.C.	.79	6.27	.66	4.94	b. Moderated by continued discounting of Alaskan and West Coast sales price by Exxon & Sohio.
		1,300,000	11.80	Valdez	-	6.25	.66	4.89	
		11,600,000	13.09	E & GC	2.77	6.27	.66	3.39	
		33% of total production or 385,479 bbl/day to East & Gulf Coast						4.56 av.	
Aug. 1978	ARCO	7,400,000	13.41	W.C.	.88	6.04	.76	5.73	3% decrease over previous month in average wellhead price.
	EXXON	7,000,000	12.65	W.C.	.93	6.27	.70	4.75	a. Attributable to a 3% increase in East & Gulf Coast sales and continued discounting of Alaskan and West Coast sales price by Exxon & Sohio.
		210,000	5.54	PS 1	-	-	.53	5.01	
		220,000	13.18	E & GC	2.75	6.27	.70	3.46	
	SOHIO	5,500,000	12.68	W.C.	.79	6.27	.66	4.96	
		1,050,000	11.80	Valdez	-	6.25	.66	4.89	
		12,900,000	13.14	E & GC	3.03	6.27	.66	3.18	
		36% of total production or 431,000 bbl/day to East and Gulf Coast						4.44 av.	

W.C. = West Coast
E & GC = East and Gulf Coasts
PS 1 = Pump Station 1

Prepared by:
Legislative Affairs Agency
Research Division
A. R. Latham
20 October 1978

AGO 532525

PLEASE NOTE: THE PRECEDING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

STATE OF ALASKA
THE LEGISLATURE
LEGISLATIVE AFFAIRS AGENCY

POUCH Y - STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

MEMORANDUM

September 28, 1978

SUBJECT: Legislators' Energy Background Report

TO: All Legislators

FROM: Gregg K. Erickson
Director of Research

Over the past year, the Research Division has received an increasingly large number of requests from legislators for background material on various Alaska energy issues. The attached background report represents an effort to meet this need in a more regular and formal way. Compiling a report takes a good deal of staff time, and we're not certain this is the most efficient way to get the information you need to you in a timely manner. Your comments will be very important in determining whether the effort is continued. In the next report, we will enclose a self-addressed, stamped envelope and a questionnaire, which we hope you will use to let us know your reactions.

This report is generally the work of Kay Brown, although we expect that other staff members will also contribute from time to time.

GKE:jm
Attachment

UNRESOLVED ISSUES

AGO 532526

STATE OF ALASKA
THE LEGISLATURE
LEGISLATIVE AFFAIRS AGENCY

POUCH Y · STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

ENERGY BACKGROUND REPORT FOR LEGISLATORS

September 26, 1978

NATURAL GAS PRICING LEGISLATION DELAYS PIPELINE PROJECT

The failure of Congress to enact President Carter's energy package has virtually halted progress toward securing financing for the Alaska Highway natural gas pipeline.

John G. McMillian, chairman of Northwest Alaskan Pipeline Company of Salt Lake City, says the pipeline already has slipped nearly a year behind schedule due to Congressional inaction and won't be completed until the winter of 1983-84, at the earliest.

Reports from Washington indicate the Senate will vote September 27 on the conference committee version of the controversial natural gas bill, and House consideration is expected in early October.

Most of the controversy has centered on provisions unrelated to the Alaska Highway gas pipeline, primarily whether to deregulate new gas prices in the now-regulated interstate market, or regulate prices in the now-unregulated intrastate market. The conference committee bill that reconciles vastly different House and Senate versions pleased practically no one and prompted a coalition of pro-consumer and pro-industry senators to team up against it. In light of a recent vote in the Senate that failed to send the natural gas bill back to conference committee, however, many observers predict passage.

When and if the bill is approved by Congress, it will provide a boost to the pipeline sponsors, who have been frustrated by months of delay and inaction. Work on the project cannot proceed until a price is established for the gas, and defeat of the legislation likely would mean an extended pricing proceeding before the Federal Energy Regulatory Commission (FERC).

The bill would establish a ceiling wellhead price of $1.45 per thousand cubic feet for Prudhoe Bay gas (as of April, 1977), with price escalators for inflation. The legislation would permit "rolled-in" pricing of both wellhead and transportation costs, a provision considered essential for the marketability of the gas. (Rolled-in pricing means the pipeline companies buying high-cost Alaska gas can average its cost with other,

AGO 532527

cheaper gas sources when billing consumers. Incremental pricing, in contrast, means consumers pay for Alaska gas separately--and its costs, therefore, stand out sharply compared to other gas supplies.)

The legislation does not determine who will bear the costs of gathering and conditioning the gas, leaving this point to be settled in negotiations between the North Slope producers and pipeline companies. (Any agreement reached on this point is subject to FERC approval.) The legislation does provide, however, that some of the gathering and conditioning costs may be passed through on an incremental basis to industrial and other low priority customers, thus raising the price to these consumers. While no one at present seems to understand how this complex pricing mechanism will work, FERC must figure out how to administer it and make the ultimate determination on which costs will be rolled-in and which priced incrementally.

Even with immediate action on the gas pricing bill, the Northwest project still faces a long series of hurdles before construction can begin.

It is not yet clear whether Northwest and its five partners, which are seeking to borrow massive amounts of cash, relative to their size, will be able to convince some combination of the State of Alaska, the North Slope producers and private lenders to finance the mammoth project, now estimated to cost at least $12 billion ($4.5 billion for the Alaska section alone). Nor is it clear whether the North Slope producers will be willing to produce and sell their gas, particularly if the price they are able to negotiate with the pipeline companies falls below the ceiling permitted by law. Northwest hopes to begin negotiations with the North Slope producers shortly after a ceiling price for the gas is established. These negotiations likely will address three major issues: 1) Who will pay how much for the North Slope conditioning plant necessary to prepare the gas for shipment? 2) To what extent, if any, will the producers participate in financing the pipeline? and 3) How much will the pipeline companies pay the producers for the gas?

Some observers believe it will not be possible to pay for the project with purely private financing (even with support from the State of Alaska) and that federal assistance ultimately will be required.

Besides the price and the producer sales contracts, a number of other factors also have to be resolved before Northwest can begin serious discussions with private lenders. Some of these factors are:

- A final resolution by FERC on the "variable rate-of-return," which will determine the amount pipeline companies and other equity owners can earn on their invested money. FERC now awaits public and industry comment on a revised proposal, but it is uncertain when a final decision will be made.

AGO 532528

- Approval by FERC of the tariff structure. A proposed tariff structure now is circulating among partners in the Northwest consortium; it is expected to be filed with FERC late this year.

- Appointment by President Carter and approval by Congress of a Federal Inspector. Jack Rhett, an Environmental Protection Agency official and former employee of the Army Corps of Engineers, is reported to be the leading candidate. Walt Parker, co-chairman of the Federal-State Land Use Planning Commission, also is under consideration. State officials expected a formal nomination to Congress months ago. Gov. Jay Hammond wrote President Carter a letter in early August urging quick action on the appointment. Hammond said "divisive wrangling" among the federal agencies had left the federal government's effort to build the pipeline "wholly without leadership."

- Reorganization of the federal bureaucracy to facilitate pipeline construction oversight. This reorganization, mandated by the "President's Decision and Report to Congress" that selected the Alaska Highway route over two competing proposals, will transfer to the Federal Inspector field-level supervisory authority over other federal agencies holding responsibility for various aspects of gas line construction. Congress must approve this reorganization.

- A decision by FERC on pipeline pressure and other design and engineering matters. A report from FERC is expected any day.

CANADA RECONSIDERS PLAN TO PRE-BUILD SOUTHERN PORTIONS OF THE GAS LINE

Published reports[1] indicate that delay in the United States is creating problems for the pipeline companies that will build the Canadian sections of the Alaska Highway gas pipeline project.

"Pre-building" the southern sections of the Alaska project, to allow earlier delivery of Alberta gas into the United States, has been promoted as a way to ease financing of the overall project. However, there is now talk in Canada of possibly expanding existing TransCanada pipelines for the export of excess Alberta gas (called "bubble" gas) instead of using pre-built facilities of the Alaska Highway project.

---

[1] Oilweek, August 21, 1978; Western Interstate Energy Board Newsletter No. 78-32, Sept. 1, 1978.

AGO 532532

Proposals by a group of Alberta natural gas producers, called the "ProGas" consortium, to expand existing pipelines could threaten the planned pre-building of the southern section of the Alaska Highway gas line. The ProGas group is managed by Vern Horte, former president of Canada Arctic Gas Pipeline Ltd., which backed the losing Arctic Gas route through the Mackenzie Valley.

Although the Foothills Pipe Lines consortium, which will construct the Canadian sections of the Alaska Highway gas line, has officially maintained that pre-building of the southern portions is not critical to success of the overall project, spokesmen say Foothills will fight any project that threatens pre-building.

FERC already has demonstrated its support of the pre-building concept by giving Northwest Alaskan conditional approval to import 1.04 billion cubic feet a day of Canadian gas from PanAlberta Gas Co. Ltd. (U. S. import approval means nothing without Canadian approval, now under debate.)

It is possible that both the Foothills pre-building and ProGas expansion schemes could proceed, but this will depend on how much gas the Canadian National Energy Board determines is available for export. The National Energy Board will conduct public hearings in October and November on Canada's gas supply and demand requirements, and it is expected to submit a report to the federal cabinet by the end of the year.

In a related matter, two Lower 48 pipeline companies have challenged in court FERC's action granting conditional import approval to Northwest. Midwestern Gas Transmission Company and Michigan Wisconsin Pipe Line Company appealed FERC's refusal to conduct a rehearing on the matter to the U. S. Court of Appeals, District of Columbia Circuit.

While knowledgeable opinions on the significance and likely success of the Midwestern suit vary widely, Northwest Alaskan "believes there is no foundation for the appeals," the company said in a recent newsletter. "The project's sponsors view the FERC's action as carrying out the President's Decision and Report to Congress to: 1) consider early construction for Alberta gas imports an integral part of the pipeline system; and 2) aid in the expeditious processing of all necessary government approvals."

INTERIM COMMITTEE ON GAS LINE FINANCING ORGANIZES

A legislative interim committee directed to study the possibility of a $500 million direct investment by the state in the gas pipeline met September 7 and 21 in Anchorage. The committee was created by a resolution of the last legislature.

The committee has approved an $85,000 study on the marketability of Alaska gas in the Lower 48 by the University of Alaska's Institute of Social and Economic Research, and $12,000 for a technical symposium that will bring together econometric model builders in Alaska. The committee also has tentatively agreed to retain the law firm of Birch, Horton, Bittner & Monroe of Washington, D. C. and Alaska for advice on legal and regulatory matters.

In testimony September 21, Northwest officials said their company has not yet formally asked Congress to approve a change in Section 103 of the Internal Revenue Service Code. This change is necessary before the Alaska Gas Pipeline Financing Authority, which was created by the legislature last session, can issue $1 billion in tax-exempt revenue bonds for the project. Northwest officials said they have postponed seeking the IRS change until Congress acts on the natural gas bill. They said they are optimistic that both the natural gas bill and the IRS change will be approved by Congress this year. They confirmed earlier reports that completion of pipeline construction will be delayed about a year.

In response to questions, Northwest officials told the committee the company soon will submit updated cost estimates and a revised timetable.

Committee members are Senators Frank Ferguson, Bill Sumner and Mike Colletta, and Representatives Bill Miles, Terry Gardiner and C. V. "Chat" Chatterton. So far, the committee has not elected a chairman.

RADER NOMINATED TO NORTHWEST BOARD

Retiring Senate President John Rader, Gov. Hammond's nominee to serve on the Board of Directors of Northwest Alaskan, says he expects his formal election to the board will come later this fall. Rader would serve as an ex officio, non-voting member of the board.

Legislation enacted last session creating the Alaska Gas Pipeline Financing Authority directed the governor to nominate a public member to represent the state on the Northwest Alaskan Board of Directors, subject to approval of the board.

Northwest Alaskan, one of the six partners making up the Alaskan Northwest consortium, serves as operating partner for the group.

STATE RECONSIDERS PLAN TO SELL ROYALTY GAS

Officials in the Department of Natural Resources are reevaluating the state's announced intention to sell the Prudhoe Bay royalty gas and gas liquids next spring.

AGO 532529

Commissioner Robert LeResche said recently he doubts the sale can proceed as scheduled, given all the uncertainties surrounding the pipeline project, even if Congress sets the price for Alaska gas immediately.

The department has circulated a "general notice and solicitation" to 500 firms announcing the proposed sale and setting out a tentative timetable. However, the state received only 23 letters of interest; all responses were brief and provided little concrete detail on in-state development plans. The schedule outlined in the July 19 solicitation anticipated that a final decision on whether to hold the sale would be made in March, after the legislature had reviewed and approved a "draft contract" and criteria for selecting a bidder. If a decision were made to go forward with the sale, bidders would submit "final development plans" and sealed bids in late March. The legislature then would approve a specific contract to be selected by the administration.

LeResche said this change in procedure was partly in response to criticism the administration received during the royalty oil sale to Alpetco last spring.

Of the 23 responses, North Pole Refining submitted one of the most detailed, saying it has undertaken an economic study of markets and transportation to determine whether a petrochemical facility (processing ethanes, propanes and butanes) could operate profitably in the Fairbanks-Interior region.

LeResche said the department and the Royalty Oil and Gas Development Advisory Board will continue to work with interested firms in developing plans for in-state use. In conjunction with that effort, the department is considering proposals from four consulting firms to assist the state in promoting petrochemical development.

GRAVEL'S GSOP GAINS GROUND

The U. S. Senate Finance Committee has endorsed Sen. Mike Gravel's General Stock Ownership Plan (GSOP), a scheme that would allow Alaska citizens to own shares of large energy projects such as the gas pipeline.

Gravel calls his plan "a landmark in the effort to spread the wealth more fairly without undermining the free enterprise system." Gravel predicts that the GSOP, if approved by Congress and the President, could mean $500 dividend checks to Alaskans as early as 1980, increasing gradually to $3,000 by the year 2000.

Gravel said persuading the Senate Finance Committee to attach the GSOP to the omnibus tax bill was the biggest obstacle to approval. The proposed GSOP would receive tax treatment similar to the Employee Stock Ownership Plans (ESOP) developed under IRS pension provisions more than 20 years ago, while expanding the category of eligible individuals

AGO 532530

beyond the employees of a single company. The GSOP trust would have to be sponsored by a state government; eligibility would be open to all residents of the state.

Gravel told the Senate when he introduced the legislation in June that if the State of Alaska chooses to make an equity investment in the gas pipeline, he thinks the citizens of Alaska should directly own that equity.

Financial consultant Louis Kelso, who developed the ESOP and GSOP, currently is designing an Alaska GSOP under a $180,000 contract with the Legislative Finance Division.

HAMMOND POSTPONES POINT THOMSON OIL AND GAS LEASE SALE

The state will not hold a North Slope oil and gas lease sale this fall as originally planned, Gov. Hammond announced recently.

The state had planned to lease acreage near Exxon's announced discoveries at Flaxman Island and Point Thomson, about 60 miles east of the Alyeska pipeline, on October 17. This would have been the state's first North Slope lease sale in more than nine years.

In a statement released September 15, the governor cited the federal government's failure to deal with the West Coast oil surplus, objections from local residents and the oil industry, lack of environmental data, and a dispute with the Interior Department over title to the lands as reasons for the postponement. Hammond said the problems are of such magnitude that they cannot be resolved before the federal-state Beaufort Sea lease sale, now scheduled for December, 1979. (See next item.)

Local residents in Barrow, Nuiqsut and Kaktovik expressed almost unanimous opposition to the sale at hearings conducted by the Department of Natural Resources this summer. The North Slope residents said they feared further oil development would destroy their subsistence resources and lifestyle.

Several oil companies also objected to the sale, citing legal problems that could lead to litigation and a desire for more exploration time.

The West Coast oil surplus, which daily forces about 600,000 barrels of Alaska crude to be shipped through the Panama Canal to the U. S. Gulf coast, has depressed wellhead prices for some Prudhoe oil to as little as $1.17 a barrel. The weighted average for all Prudhoe oil has dropped to about $4.38 a barrel.

"We cannot expect producers to pay full value for leases, nor can we expect to gain full value for oil produced from these leases until this market problem is solved," the governor said. "I do not intend to sell

AGO 532533

resources belonging to the people of Alaska at the cut-rate prices which are resulting from the federal Department of Energy's inaction."

PLANS PROCEED FOR BEAUFORT SEA SALE

With cancellation of the Point Thomson sale, attention now turns to preparations for a major federal-state offshore sale in the Beaufort Sea in December, 1979.

In July, The U. S. Interior Department and the state announced selection of 186 tracts (about 514,200 acres) proposed for inclusion in the sale. The tracts were selected for further social, economic and environmental study based on industry interest and a preliminary assessment of their oil and gas potential. The tracts lie from four to 20 miles offshore in an area between the National Petroleum Reserve in Alaska and the Arctic National Wildlife Range.

The federal Bureau of Land Management is preparing a draft environmental impact statement, and the state will prepare a social, economic and environmental analysis on portions of the proposed sale area. Public hearings on these documents are scheduled for May, 1979.

After the final environmental impact statement is completed next August, the governor and the Interior secretary will decide whether to hold the sale.

The proposed Beaufort Sea sale already is generating vigorous opposition from North Slope residents and environmental groups, who claim that current technology is inadequate to protect the Arctic from the risks of offshore drilling. News reports indicate that the Greenpeace Foundation of Portland, Ore., and other national environmental groups are gearing up to mount a campaign against the Beaufort sale.

FEDERAL GOVERNMENT PONDERS OIL SURPLUS

Three task forces in the federal Department of Energy are considering solutions to reduce the growing surplus of heavy-sour crude oil on the West Coast.

The federal government already has eased restrictions on the export of California residual fuel oil from the West Coast, and state officials are moderately optimistic that these changes portend a more comprehensive solution.

The West Coast surplus has held state revenues from royalties and severance taxes far below levels predicted several years ago. The state has been arguing that failure to relieve the surplus will severely curtail future oil exploration and development in Alaska and undermine the federal government's effort to increase domestic production and cut foreign oil imports.

AGO 532534

Members of the Alaska administration and legislature have worked since last spring with California officials to develop a three-point plan for relieving the surplus: convert ("retrofit") and equip existing West Coast refineries to handle more Alaska and California crude oil, construct one or more of the proposed west-to-east pipelines, and permit the export or exchange of North Slope and California crude oil.

Export of Alaska crude is prohibited by law unless approved by the President and the Congress. Thus, Alaska's strategy has been to seek and propose solutions that accommodate both national and state concerns.

In testimony before a Congressional subcommittee August 21, Revenue Commissioner Sterling Gallagher warned that continued federal inaction may curtail future Alaska oil production.

"If the federal government is not interested in taking the action needed to solve the situation, then I am afraid that badly needed oil and gas in the Alaskan Arctic and in California will not be developed beyond current production levels. In addition, the chance to reduce costly transportation charges and also to improve the nation's balance of payments situation will be lost," Gallagher said.

"If the federal government does not have the resolve to take effective action, then this inaction will have likely impact on the willingness of Alaska and industry to develop additional resources at this time and require Alaska to examine all courses of action which it might take without federal participation," he said.

Rep. C. V. "Chat" Chatterton, testifying at the same hearing before the Special Investigations Subcommittee of the House Interior and Insular Affairs Committee, urged that restrictions be lifted to allow the export of Alaska oil.

"The optimal fiscal interests of the people of Alaska can best be served by Congress' outright repeal of those sections of PL 93-153, the Trans-Alaska Pipeline Authorization Act, which restricts Alaskan oil transported through the Alyeska Pipe Line to being marketed in the U. S. unless presidential and congressional approval is obtained for exemption," Chatterton said.

Chatterton serves on a joint interim West Coast Oil Surplus Committee, which is chaired by Rep. Clark Gruening. The committee has retained consultant Arlon Tussing and also has approved a $145,000 study, to be conducted by Battelle Pacific Northwest Laboratories, on future West Coast supply-demand balances and limits to refinery expansion.

FOOTHILLS CONSORTIUM PROPOSES OIL PIPELINE THROUGH CANADA

Officials of a Canadian pipeline consortium toured Alaska recently seeking support for new alternatives to transport North Slope crude to inland U. S. markets.

Foothills Oil Pipe Line Ltd., jointly owned by Alberta Gas Trunk Line and Westcoast Transmission, would like to build an oil pipeline paralleling the Alaska Highway gas pipeline or an oil pipeline originating in Skagway. (Foothills is also sponsoring the Canadian portions of the Alaska Highway gas line project.)

One alternative proposed would route the new oil line from Delta Junction near Fairbanks down the gas line corridor into Edmonton, where the oil would then enter existing pipelines for transport to the mid-eastern United States. However, this would leave the southern portions of TAPS underutilized, assuming North Slope production remains at its current level. Foothills officials said Sohio, the producer with the most surplus oil and a major customer for any new line, would have to pay the full TAPS tariff to Valdez, even if the oil were diverted to a new line near Fairbanks. (This is the same problem faced by North Pole Refining, which is charged the full tariff even though it takes its oil out at Fairbanks.)

In an attempt to accommodate Sohio's problem, Foothills developed a second alternative. Under this plan, oil would be moved in small tankers from Valdez to Skagway, and a new pipeline would be constructed along the Alaska Highway corridor to connect with existing lines in Canada. Foothills officials also envision a major oil port at Haines to accept supertankers carrying sweet, foreign oil, which would be shipped by smaller tankers or a new pipeline to the less accessible Skagway port.

Foothills officials said they already have made several presentations to the federal Department of Energy, although they have not filed a formal application with the Federal Energy Regulatory Commission.

"We are here now because your Department of Energy says it's time to decide if we want to proceed with a formal application," Ed Phillips, senior vice president of Foothills Oil Pipe Line Ltd., said during a visit to Juneau September 21. "We're looking for a consensus and not the adversary hearings we had with the gas line."

Foothills officials said they considered their proposed oil pipeline to be competing with two long-standing proposals to move Alaska oil to U. S. inland markets by northern pipelines. One would involve shipping oil to Kitimat, British Columbia, where it would move by pipeline to Edmonton, Alberta, and then into existing pipelines. The so-called Northern Tier proposal would require a major oil port at Port Angeles, Wash., and construction of a new pipeline across the northern states to the Midwest. Both proposals have met stiff opposition from environmentalists, fishermen and others.

AGO 532536

Phillips predicted that Canada's National Energy Board would finally and formally reject the Kitimat proposal within two weeks.

President Carter has asked Foothills for a formal proposal by the end of the year, Phillips said. He said he expected Carter to make a formal Presidential decision selecting one of the competing northern pipeline routes sometime after May, 1979, when the Department of Energy will make a recommendation.

The Canadian and American governments have been reluctant to approve the Kitimat and Port Angeles port sites, Phillips said, because many believe environmental risks outweigh potential benefits. Alaskans might view an Alaska oil port differently, he speculated, since the state stands to gain relief from the West Coast surplus and increased revenues from higher wellhead prices.

Foothills would build the new oil line in partnership with Northwest Pipeline Corporation of Salt Lake City, the same firm sponsoring the Alaska portions of the gas line.

While in Alaska, Foothills officials briefed legislators and high-ranking members of the administration, and met informally with environmental groups, the Coast Guard, and the Skagway and Haines Chambers of Commerce.

ALPETCO SEEKS SITE FOR PETROCHEMICAL FACILITY

Alaska Petrochemical Co., winner of the right to purchase 150,000 barrels a day of state royalty oil, has selected four potential sites for its refinery and petrochemical facility.

The four sites are City of Valdez, City of Seward, Kenai Native Association (Wildwood site) and the Matanuska-Susitna Borough (Pt. McKenzie and others). Under terms of the contract signed with the state last spring, Alpetco must make its final choice by December 18.

The company is conducting subsurface soil tests at each location, as well as preliminary environmental, resource and social studies.

In August, Alpetco representatives met in Tokyo to discuss participation in the project with several Japanese groups. Charles Honig, board chairman and president of Alaska Interstate Co. (which owns 60 percent of Alpetco), said Japanese interest in the project is "most encouraging."

COMMITTEE STUDIES COMPREHENSIVE ENERGY POLICY

The State Energy Policy Committee, chaired by Rep. Bill Miles, has been working during the interim to develop a comprehensive state policy encompassing a broad range of energy issues.

AGO 532537

The committee is studying the relationships between the state departments, divisions and regulatory agencies that deal with energy matters; the state's approach to energy conservation; the use and development of conventional (oil, gas, coal, hydroelectric) and alternative (solar, wind, tidal, geothermal) energy resources; and the state's perspective on and conformance with national energy policy.

HALLORAN

STATE OF ALASKA
THE LEGISLATURE

POUCH Y STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

LEGISLATIVE AFFAIRS AGENCY

ENERGY BACKGROUND REPORT FOR LEGISLATORS

No. 3 December 8, 1978

CONTENTS

Gas Pipeline — Page

Northwest distressed by "bureaucratic delay," wins in court..... 1
Alaska Highway gas pipeline threatened by changing energy outlook..... 3
Alaska urges 1440-psig pressure for gas pipeline..... 6
Legislators visit Canada..... 8
Prudhoe reservoir study progresses..... 9
Legislature and administration hire energy consultants..... 10

Oil Surplus

Alaska officials to visit Mexico..... 10
Foothills officially proposes Skagway oil port and pipeline..... 12
Gravel proposes repeal of oil export restrictions..... 14
DOE study shows benefits of exports..... 15
Congressional committee issues West Coast oil surplus report..... 16
Sohio pipeline moves one step closer..... 17

Royalty Oil and Gas Development

Prudhoe royalty gas sale still in doubt..... 18
Pacific Alaska LNG project proceeds; Alaska's right to withdraw Cook Inlet royalty gas uncertain..... 20
Alpetco selects Valdez for facility site..... 23

Leasing

Natives protest Exxon drilling at Duck Island..... 24
Interior Department considers P.L.O. 82..... 26
Federal government revises OCS leasing schedule..... 27
State favors joint bidding for Beaufort sale..... 28

Other

Economists see "hard landing," favor direct distribution of oil wealth..... 28
Hammond will ask for Susitna appropriation..... 30
State Energy Policy Committee adopts policy guidelines, develops strategy for implementation..... 31
Alaska Pipeline Commission considers "allocation of service" for TAPS..... 33

-- Compiled by Kay Brown, Policy Analyst --

AGO 532539

NORTHWEST DISTRESSED BY "BUREAUCRATIC DELAY," WINS IN COURT

A financial advisor to the Alaskan Northwest pipeline consortium says the possibility of obtaining private financing for the $12 billion project "looks pretty grim at the moment."

"Basically, we are very pessimistic about the probability of private financing because of the ever-increasing entanglement of the Washington bureaucracy and the delays caused by Washington," said Mike Stanfield, vice president of Loeb Rhoades, Hornblower and Co., a Northwest advisor.

"I'm not saying we're dead, but the government has got to wake up and change things," Stanfield said. "It's all in Washington's hands. They are going to have to decide whether they want the pipeline or not, and if they do, they're going to have to change some things."

Stanfield said the failure of the Federal Energy Regulatory Commission to resolve the Incentive Rate of Return on equity, the pipeline's design, and the ownership and cost responsibility for the North Slope conditioning facilities are only a few of the partnership's problems.

"The Federal Inspector was supposed to have been appointed 14 months ago. Because that hasn't happened, a number of other federal agencies are working counter to each other and to us," he said.

The consortium's Board of Partners recently reduced the operating budget substantially, Stanfield said, but he declined to give details.

Stanfield said FERC's November 29 order on the Incentive Rate of Return didn't resolve any substantive issues.

"We don't consider it a decision, but rather a furtherance of bureaucratic red tape," he said. "We're very distressed by the fact that they didn't decide anything."

FERC deferred action and scheduled a hearing on one of the main issues considered a problem by Northwest--whether the Allowance for Funds Used During Construction (AFUDC) account should be included in the ratio of actual construction costs to projected construction costs. This ratio will serve as the basis for determining what rate of return the project is allowed to earn on equity.

The Incentive Rate of Return (IROR), mandated in the President's Decision and Report to Congress selecting the Alaska Highway route through Canada, is designed to control construction cost overruns. The IROR would allow pipeline companies and other equity investors to earn a high rate of return if the project is constructed within or under budget, but would reduce earnings if the project ultimately costs more than projections.

FERC has proposed that AFUDC funds be included in the actual construction costs used to determine the cost performance ratio on which IROR will be based. Alaskan Northwest has said inclusion of this factor could jeopardize private financing because it penalizes the project sponsors for government-caused delay and other factors beyond their control. Any delay in construction will increase the AFUDC account, which would reduce the allowed rate of return under FERC's present IROR proposal.

"One of the basic problems is that none of FERC's decisions is final; everything is subject to reconsideration," Stanfield said. "They are not doing anything but creating paperwork and causing anxiety."

Earlier in November, John G. McMillian, chairman and chief executive officer of Northwest Alaskan, told a press conference in Washington, D.C., that the company remains optimistic about private financing.

"Rumors of our demise have been greatly over-exaggerated," McMillian was quoted in press accounts as saying. "We still believe, given the conditions that we hope will be approved by the Federal Energy Regulatory Commission, that we can finance the project privately, without government aid."

McMillian said, however, that FERC's Incentive Rate of Return proposal must be modified along lines suggested by Northwest in order for private financing to be achieved.

McMillian also said Northwest will need government support in the form of tax-exempt status for $1 billion in bonds to be issued by the State of Alaska. Congress last session failed to pass a change in the IRS code that would have allowed issuance of the bonds, but McMillian said his company will try again next year to get the necessary changes approved.

However, Sen. Mike Gravel told a San Francisco meeting of the legislature's Gas Pipeline Financing Committee that it appears the proposed IRS change is "dead for now" due to opposition of the Treasury Department and others.

On November 14, the same day as McMillian's press conference, the New York Times reported that: "Financially, the gas pipeline faces so formidable a series of hurdles that it ultimately may require outright Federal financing, industry sources expect."

But not all the news has been gloom and despair for supporters of the pipeline project.

The U. S. Court of Appeals, District of Columbia Circuit, recently dismissed an appeal by two Lower 48 pipeline companies to review a FERC order granting Northwest Alaskan conditional approval to import Canadian gas.

Northwest wants to import 1.04 billion cubic feet of gas a day from Pan-Alberta Gas Ltd. and deliver it through "pre-built" southern sections of

the Alaska Highway gas pipeline. Although this arrangement has been conditionally approved by FERC, the Canadian government has not yet granted export permission.

Midwestern Gas Transmission Co. and Michigan Wisconsin Pipe Line Co. had challenged FERC orders on a number of grounds, including lack of authority, an inadequate record, anti-trust violations, and violations of constitutional and statutory rights to a hearing.

In its November 2 ruling, the court affirmed FERC's jurisdiction to act on the matter under the Alaska Natural Gas Transportation Act and the Natural Gas Act. The court dismissed several challenges to the merits of the Commission's decision as not ripe for review. With respect to the single issue found ripe for review--whether FERC unlawfully refused to hold a hearing before issuing the conditional authorization to Northwest--the court upheld FERC's action as within the bounds of the Constitution and the Natural Gas Act.

A few days after the court decision, the companies responsible for the Western Leg of the Alaska Highway project filed applications with FERC seeking the necessary authorizations.

Northwest Alaskan applied for permission to sell up to 240 million cubic feet of Alberta gas a day to Pacific Interstate Transmission Co. (a subsidiary of Pacific Lighting Corp.) for ultimate delivery to markets in southern California. Related applications were filed by Pacific Transmission Co., Northwest Pipeline Corp., El Paso Natural Gas Co. and Pacific Interstate. Together, the applications would accomplish delivery of this gas from the International Boundary near Kingsgate, British Columbia, to the Arizona-California border, where Pacific Interstate would sell the gas to Southern California Gas Co.

The remainder of the 1.04 Bcf/d imported from Pan-Alberta, or about 800 million cubic feet a day, will be delivered at Monchy, Saskatchewan, and purchased from Northwest Alaskan by United Gas Pipe Line Co., Panhandle Eastern Pipe Line Co. and Northern Natural Gas Co.

ALASKA HIGHWAY GAS PIPELINE THREATENED BY CHANGING ENERGY OUTLOOK

A legislative consultant says the Alaska Highway gas pipeline, faced with competition from Mexican, Canadian and growing surpluses of Lower 48 gas, may be delayed indefinitely unless significant progress is made in the next several months.

Consultant Arlon Tussing told the legislature's Gas Pipeline Financing Committee at an Anchorage meeting November 27 that the energy supply picture in North America is changing rapidly and that competition from other supplies could make expensive arctic gas unmarketable.

"Oil and gas in North America is going to be coming on stream faster than demand is going to grow in the next four to five years," Tussing said. "The availability of conventional energy in North America has been greatly underestimated...Mexico is not a myth. The finds in Mexico are far bigger than anything ever expected in conventional resources in North America..."

Higher prices allowed under the new Natural Gas Policy Act of 1978 have created a current gas surplus of about 1 trillion cubic feet in Lower 48 markets, and energy officials say the surplus may last for three to five years.

Tussing said Energy Secretary Schlesinger and the CIA have been aware of large Mexican discoveries for three years, and yet they deliberately and self-servingly ignored and concealed these supplies in order to push President Carter's energy program through Congress.

Carter's energy strategy is based on the premise that the world is running out of conventional energy and that a "crunch" or tightening of supplies will confront the nation sometime in the 1980s. This view gained wide acceptance after the 1973-74 Arab embargo and quadrupling of oil prices.

"The crunch doesn't look as imminent as it did several years ago," Tussing said. "I don't think there's going to be a crunch, but you can't know for sure, you can't predict."

In any event, he said, the uncertainty of the situation is going to have a significant impact on the willingness of gas companies in the Lower 48 to sign long-term contracts for high-cost gas, on the willingness of institutional investors to invest in high-cost projects, on the willingness of state public utility commissions to approve high-cost purchases, and on the willingness of Congress to consider financial backstopping.

If the real price of oil doubles by 1985 as Department of Energy officials and Exxon predict, Tussing said, the market will be able to absorb all the gas that can be transported from the Arctic by pipeline. But if not, the market won't accept Alaska gas without federal subsidy.

"One of the things the state is going to have to face up to with respect to this project and its oil policies is the possibility that the world will face a buyers' market in energy for the next three to five years, and maybe to the turn of the century. Economic strategies that depend on a sellers' market, that assume Arctic resources will be needed, will have to be reassessed," Tussing said.

Tussing presented to the committee the first part of a study that he and Connie Barlow are conducting under an $85,000 contract between the University of Alaska's Institute of Social and Economic Research and the Research Division of the Legislative Affairs Agency. Tussing described the report, titled "An Introduction to the Gas Industry, with special reference to

the proposed Alaska Highway gas pipeline," as an attempt to explain in plain English what gas is, how it is sold and marketed, how gas projects are financed, and how government regulates the industry. Copies of the report are available from the Anchorage and Fairbanks legislative information offices or from the Research Division of the Legislative Affairs Agency.

When asked by Sen. Bill Sumner for his "best guess" of how long the gas line sponsors have to put the pieces together, considering all the variables, Tussing responded: "You may well be faced with making the decision of whether to go with it or kill it in this upcoming legislative session. I don't know. The sponsors cannot say this thing is precarious or that it may fall apart at any moment. Their emphasis is on maintaining momentum, on maintaining everybody's conviction that this is a viable project, that things are happening step-by-step. But if you have six months or a year when nothing happens, this erosion (of the political climate) can be fatal...A federal pipeline coordinator hasn't been appointed, there haven't been sales or transportation contracts, there are no firm financial commitments from the banks, and so on. The state may have to make the next move, or series of next moves, dramatic ones to keep the project alive."

The sponsors of the Alaska sections of the pipeline have asked the state to contribute $500 million in equity to the project, and have been pushing for an early state commitment. Committee Co-chairman Rep. Bill Miles and Natural Resources Deputy Commissioner Fred Boness agreed, however, that it will not be possible to have a recommendation on equity financing ready for the legislature when it convenes in January.

One of the next big hurdles faced by the pipeline sponsors is to secure sales contracts for the gas. Negotiations between the North Slope producers and the pipeline companies were unable to proceed until Congress passed the Natural Gas Policy Act of 1978, which set a Prudhoe Bay wellhead ceiling of $1.45 per million BTUs as of April, 1977, plus inflation.

Tussing said gas sale negotiations have not progressed very rapidly because details of implementing the bill still are being worked out by FERC. The protracted debate in Congress over the energy bill has had two adverse effects on the gas line, Tussing said.

"First, it has delayed us to the point that the whole energy picture has changed, and second, it has held out to the state and the producers a totally unrealistic price. We both would have been tickled to get 75¢ plus inflation. This puts the legislature in a tough spot. Can you politically agree to a 65¢ or 75¢ price, even if the producers were willing to? At least one of the producers indicates they're going to hold out hell or high water for the ceiling," Tussing said.

Frank Zarb, who headed the Federal Energy Administration under former President Ford, said during a visit in Juneau December 5 that it is his "best judgment at the moment" that the Alaska Highway gas line cannot be financed in its present form. Zarb, a non-paid advisor to Gov. Hammond and a general partner in the investment banking firm Lazard Freres & Co., said increased supplies of Canadian, Mexican and non-conventional Lower 48 gas may make investors unwilling to finance the pipeline.

"Three years ago, we could have ridden (the pipeline) on a white horse. We could have sold all kinds of gimmicks to support it. But, conditions have changed," Zarb said.

Zarb said he doesn't think an equity investment by the state will make the difference in whether the pipeline is built or not.

Zarb did not rule out congressional support, in the form of federal subsidy, for the line. He said that once people realize that short-term gas surpluses will be exhausted in the 1980s, they may conclude that it is in the national interest to go ahead and build the line today, when it would cost less.

Legislative consultant Milton Lipton, in a presentation to the Legislative Council December 6, said he thinks the gas line eventually will be built, although it is likely to be delayed.

The new Canadian and Mexican gas supplies may affect the timing of gas pipeline construction, he said. The sooner firm commitments can be arranged, he said, the more likely it is that the line will be built. If there is too long a delay, Lipton said, U. S. policy makers may reassess their commitment to the Alaska pipeline and attempt to rely on Mexican gas.

ALASKA URGES 1440-psig PRESSURE FOR GAS PIPELINE

The State of Alaska has asked the Federal Energy Regulatory Commission to select 1440-psig as the operating pressure for the proposed Alaska Highway gas pipeline.

Alaska submitted its comments in response to a report by FERC's Alaska Gas Project Office (AGPO) that favored a 1260-psig operating pressure. The full commission has yet to address the matter, and the AGPO report was not an official FERC finding.

Alaska urged FERC to hold a hearing in the near future to gather additional information on the pressure question, saying it does not believe "the commission now has the legal or factual foundation to issue an order establishing the system pressure."

The higher pressure 1440 system would be able to carry a greater volume of gas and of Natural Gas Liquids (NGLs), specifically butane. If the butane is left in the gas stream, its presence will raise the BTU value of the gas, Alaska said. "Gas consumers would receive a direct, valuable benefit: higher heating value than they would otherwise receive because of the presence of natural gas liquids not used for petrochemicals," the state said.

"Moreover, a 1440 system has the promise of more efficient, lower cost operation as higher throughputs occur. Alaska believes the relatively small additional costs are a worthwhile premium for its future."

Atlantic Richfield, one of the major North Slope producers, also urged FERC to approve a 1440 psig system, while Sohio told FERC it favors a 1260 system. The Alaskan Northwest pipeline consortium, which will build the Alaska sections of the pipeline, strongly favors the lower-pressure, 1260 alternative.

The partnership is proceeding with design, environmental and cost-estimating activities on the assumption that pressure will be 1260 and throughput will be 2.0 to 2.4 billion cubic feet a day. "Changes in these assumptions will cause substantial delay," Northwest Alaskan said in recent comments.

The partnership agrees with the AGPO report that "in order to justify an increase from the presently proposed pressure level of 1260 psig, it would be necessary to (1) receive the concurrence of the Canadian government, (2) assure that the consumer will benefit from the decision, and (3) assure that the project can still be privately financed," Northwest said.

If a system higher than 1260 is selected, Northwest said, the Canadian government will require extensive testing, which would delay the project about two years and "adversely affect the system economics."

The State of Alaska, however, said in its comments that testing a 1440 system may not be significantly different than testing a 1260 system. "Alaska suspects...the degree of technological advance is relatively the same for each as is the testing required."

Northwest, which asked FERC to resolve the matter "as soon as possible," said there has been "no demonstration by the producers or others that sufficient gas supply will be available to fully utilize the capacity of the higher pressure system and thereby achieve the potential economic benefit....[T]hroughput volumes over 3.0 billion cubic feet per day appear unlikely; and the prospect of achieving 4.0 billion cubic feet per day from Alaska is highly remote. In view of these considerations, the judgment to construct the 1260 psig system is sound."

Yet the state said the lower 1260 pressure would be "less than optimally designed given the potential of Alaskan reserves. The costs of later adding capacity to the gas line are substantial and suggest the advantages of building extra capacity now as an insurance policy."

LEGISLATORS VISIT CANADA

Preparations for the Alaska Highway gas pipeline are proceeding much faster in Canada than in the United States, Reps. Bill Miles, Terry Gardiner and Sam Cotten learned on a recent nine-day tour of Canada.

The legislators visited Calgary, Edmonton, Toronto and Ottawa, and met with dozens of industry and government officials.

"The major finding stemming from the Gas Pipeline Committee's visit to Canada is that the Canadian portion of the Alaska Highway Pipeline Project is ready to proceed and that Canadians support the overall project," Legislative Affairs staffer Larry Eppenbach, who also made the trip, said in a preliminary report. "The readiness of the Canadian segment of the pipeline with respect to the major regulatory and financial issues was clearly displayed."

The legislators also found that:

-- The Canadian National Energy Board (NEB) will complete gas demand and supply studies by February and should act on specific export proposals by next July.

-- The Northern Pipeline Agency (NPA), created by act of Parliament last April, is now fully operational and moving effectively to address Native claims, labor, construction and permitting issues. NPA does not expect the claims issue to impede pipeline construction. Local hire is specially provided by Canadian law granting a preference to Native northerners.

-- Any pre-building of the southern portion of the pipeline, to support early export of Alberta gas, will depend on sufficient assurances (in the form of gas sales contracts and financial commitments) that the northern portion of the line will be built.

-- The Foothills Pipeline consortium, sponsors of the Canadian segments, intends to raise about $1 billion of equity capital in Canada and about $4 billion of debt in the United States, where interest rates on debt capital generally are lower. Financing for the Canadian sections should be available on reasonable terms once financial commitments are made for the U. S. segments.

-- The Alberta Heritage Fund, a nearly $4 billion trust fund of Alberta Province, has not been asked to help finance the Foothills project. The fund would consider participation only with respect to debt financing.

The legislators also found that the relationship between the Canadian oil industry and government is markedly different than in the United States. A number of Canadian government and quasi-government organizations are directly engaged in the oil and gas business, including:

-- Petro-Canada, a crown corporation owned by the federal government, which has options on federal leases and a $1.5 billion capital draw on the treasury. The corporation owns one-third of West Coast Transmission Co., has investments in the Arctic Island area, and has proposed moving gas from the Arctic Islands to the East Coast by LNG tankers.

-- Alberta Energy Company, which is jointly owned by Alberta Province and small Canadian shareholders. The company owns gas development leases, a synthetic crude pipeline and coal mine, and is proposing a synthetic natural gas and petrochemical project.

-- Alberta Gas Trunkline, one of the major gas transmission, exploration and development companies in Canada. AGTL is a major participant in the Foothills project and has recently purchased Husky Oil Co. AGTL began as a government-supported corporation and continues to have three members of its board of directors appointed by the Alberta government.

-- Trans-Canada, a regulated public utility that owns and operates the largest gas transmission facility in North America. The Canadian government formerly owned a portion of Trans-Canada, but successful operation in the 1960s provided sufficient revenues to pay back the Canadian government for its ownership share.

PRUDHOE RESERVOIR STUDY PROGRESSES

Rep. Chat Chatterton, Gregg Erickson, and Dr. Todd Doscher, the legislature's reservoir engineering consultant, recently met in Denver with H. K. van Poollen and his staff to review progress on the three-dimensional Prudhoe Bay reservoir simulation study. Van Poollen is conducting the study under contract with the state Division of Oil and Gas. Joe Green, project officer for the division on this study, also attended.

All participants at the meeting generally agreed that the study is coming along in good order. Due to the need for some additional technical analysis, which all parties at the November 27 meeting agreed was necessary, results of the work originally scheduled for completion in February now are expected in late March.

The results of this study should provide the legislature with the best available information on such critical questions as the amount of oil that may be lost over the life of the field as a consequence of gas production for sale, and the effects of water injection into the field. The simulation study will not in any sense be final, however, since geological information derived from continued development drilling and

AGO 532548

information gained from production history will need to be continually updated to keep the model current. Those participating in the meeting generally agreed that the consultants, the Division of Oil and Gas, the producers, and others with interests in the field have reached agreement on broad outlines for the model's structure.

LEGISLATURE AND ADMINISTRATION HIRE ENERGY CONSULTANTS

The Gas Pipeline Financing Committee has approved $25,000 for San Francisco consultant Louis Kelso to design a General Stock Ownership Corporation (GSOC) specifically for financing the gas pipeline.

The administration will contribute $10,000 to $15,000 for Kelso's gas line project, Sen. Mike Colletta told the committee at its Anchorage meeting November 27. The committee met with Kelso in San Francisco earlier in November to discuss the possibility of using the GSOC as an alternative to direct state investment in the pipeline. Kelso already has a $180,000 contract with the Legislative Finance Division to design a general Alaska GSOC.

The committee also approved a $125,000 contract with the White Weld/ Merrill Lynch consulting firm to compare the state's oil and gas "framework of taxes, contracts and regulation to those of other states, governments and organizations functioning as major petroleum resource owners." The firm will examine "the strengths and weaknesses of alternative institutional frameworks under which oil and gas resource development could take place in Alaska." Rep. Terry Gardiner was named project director.

Revenue Commissioner Sterling Gallagher has retained the Washington, D.C., law firm of Wilmer, Cutler & Pickering under a $5,000 contract to study how federal securities laws will affect the organization and operation of a GSOC. The firm already has produced a report.

In addition, Gallagher said the Department of Revenue has hired the National Economic Research Associates under a $70,000 contract to study gas pipeline tariff questions.

ALASKA OFFICIALS TO VISIT MEXICO

With prospects for gaining federal permission to export Alaska oil brightening, state officials will visit Mexico this month to lay the groundwork for a three-way swap between Mexico, Japan and Alaska.

Natural Resources Commissioner Robert LeResche and legislative consultant Arlon Tussing are scheduled to leave December 10 for Mexico, where they will meet with Jorge Diaz Serrano, head of Pemex, the national oil company.

Tussing said the purpose of the trip is "to get an informal, general understanding that Mexico will work with Alaska to put together an oil swap, with the first step being that Alaska royalty oil would be sent to Japan in return for Mexican oil exported to a refinery on the U. S. Gulf."

President Carter has scheduled a trip to Mexico February 14-16, and it has been reported he will discuss the proposed Alaska-Mexico oil swap with Mexican President Portillo.

Tussing has recommended that the state apply for a license to export Alaska royalty oil, which would require President Carter himself to make a decision on the matter. Such an "action-forcing" tactic likely will be necessary to overcome political fence-sitting by the Carter administration, Tussing said in a November 13 memo to LeResche and Rep. Clark Gruening, chairman of the legislature's interim West Coast Oil Surplus Study Subcommittee.

"Because the state's object is an open-ended procedure facilitating exports on a long-term basis, not just a single short-term royalty oil sale, (1) it is neither necessary nor politic to extract the last possible penny at the wellhead, if sacrificing some revenue would make this deal more acceptable to important political constituencies, while (2) a quite tolerable outcome would be for the President to turn down this deal and instead establish a general, permanent regulatory system for oil exports," Tussing said in the memo.

While any number of swap arrangements are possible, Tussing said, "the simplest arrangement from the state's standpoint would be one in which it had to deal with only one other party who would take possession of the Alaska crude, arrange the actual exchange, and pay the state for the foreign oil it imported into the United States. The most obvious choices for this role are major international oil companies, which have established relationships with Japanese refiners, owned or affiliated refineries in various parts of the United States, and tankers under charter. Thus, I would urge that, for simplicity, the first 'sample' royalty oil exchanges be negotiated on a one-stop basis with a major oil company."

In order to help overcome public and congressional opposition, it would be best if the oil imported in return for Alaskan exports was not Middle Eastern, but Mexican, North Sea or Indonesian.

"The logic of an exchange involving Mexico is the most powerful among the three alternatives," Tussing said, "because establishing such exchanges as a legitimate long-term logistical strategy would reduce the transport burdens on both Mexican and Alaskan oil--the former would be marketed around the Caribbean and on the East Coast of the United States, while the latter would be sold around the Pacific Basin. This arrangement could conceivably forestall the absurdity of having to build an unnecessary west to east pipeline in the United States or Canada."

Inside D.O.E., a weekly report published by McGraw-Hill, recently quoted unnamed DOE sources as saying that if the administration decides to approve the export of Alaska crude, Carter probably will make the announcement in June when restrictive legislation expires.

Tussing told the Gas Pipeline Financing Committee at its most recent meeting that he is "very optimistic" that exports for Alaska oil will be approved in the foreseeable future.

Administration energy advisor Frank Zarb, who opposed the export of Alaska oil when he worked for former President Ford, said he gives the swap proposal no better than a 40 percent chance of success. He said any swap involving Mexico would have to be part of a total resolution of U. S. and Mexican energy policies.

Zarb suggested that the state promote the swap on grounds it would benefit consumers and help reduce America's dependence on imported Arab oil.

FOOTHILLS OFFICIALLY PROPOSES SKAGWAY OIL PORT AND PIPELINE

Foothills Oil Pipe Line Ltd., a Canadian consortium that wants to build an oil pipeline from Skagway to Alberta to move Indonesian and surplus Alaska crude, recently filed formal application with the Secretary of the Interior seeking certification for the project.

Under the "Crude Oil Transportation Systems" law passed by the last Congress, President Carter will select a west-to-east oil pipeline from several competing proposals. Deadline for filing applications with the Secretary of the Interior was December 8.

The Foothills proposal is in direct competition with the proposed Northern Tier pipeline, which would run from Port Angeles, Washington, to Clearbrook, Minnesota.

Foothills' application was filed by the company's U. S. associate, Northwest Energy Co. of Salt Lake City. The proposed oil line would be built by the same companies sponsoring the Alaska Highway gas pipeline, including Northwest Energy Co. and Canada's Foothills Pipelines Ltd., a joint venture of West Coast Gas Transmission Co. and Alberta Gas Trunkline.

The proposed oil pipeline, now estimated by the sponsors to cost about $950 million (1978 dollars), would run from Skagway across British Columbia and the Yukon Territory to Keg River in northwestern Alberta. Existing pipelines would carry the oil to Edmonton, Alberta, and into the U. S. Midwest.

Ron Rutherford, executive vice president of Foothills Oil Pipeline Ltd., said the average tariff from Skagway to Keg River will be about $1.02 per barrel. Transportation costs from the North Slope to Chicago, he said, will be about $8.30 per barrel. If the oil sells for $13 a barrel in Chicago, the North Slope wellhead would be about $4.70.

The company is pursuing the Skagway route, rather than an alternate overland route that would have connected with TAPS at Delta Junction near Fairbanks, because there does not appear to be enough North Slope oil to support the project for the number of years required, Rutherford said. The Skagway port will be able to accept oil from Indonesia, Saudi Arabia and other parts of Alaska. The Delta Junction route also would cost more, about $1.7 billion.

All tankers will go directly to Skagway, rather than to a tank farm at Haines as earlier proposed. As a concession to environmentalists, all tankers will go around Cape Ommaney and up Chatham Strait, rather than through Icy Strait as originally proposed.

Tanker traffic into Skagway will be slightly more than one tanker a day, and tankers will not exceed 81,000 tons.

Ed Phillips, president of Foothills Oil Pipeline Ltd., said he thinks Alaskans are going to support the project. "We were encouraged by the people we talked to in Alaska," he said. "If we'd had any red flags or signals that the state didn't want it, we wouldn't be committing to spend the millions of dollars it's going to cost to process this application."

However, opposition already is surfacing in the state. The state Division of Policy Development and Planning is currently writing an analysis of the Foothills proposal based on comments from eight state departments. Craig Lindh of DPDP said the analysis, which will be completed by the end of the year, will examine the pipeline's effect on wellhead values and the environmental risks of tanker shipments through Southeast Alaska, among other things.

The state Department of Fish and Game told DPDP it opposes a major oil port at Skagway.

"It is particularly distressing to see additional prime Alaskan fisheries subjected to environmental degradation as a result of inadequate foresight in routing the trans-Alaska oil pipeline," said Richard Logan, chief of Fish and Game's Habitat Protection.

"The demonstrated inadequacy of oil spill containment and cleanup capabilities in marine spills leaves a virtual guarantee that important marine resources and coastal habitat would be damaged in the event of a spill," Logan said in a memo to DPDP.

Revenue Commissioner Sterling Gallagher opposes the Foothills proposal on economic grounds, claiming it will produce a netback wellhead too low to stimulate development of economically marginal North Slope fields.

Gallagher says it is definitely more expensive to move Alaska oil by pipeline to the Midwest than to swap Alaska oil to Japan in exchange for Mexican oil delivered to the U. S. Gulf Coast.

"I'm not opposed to a pipeline as long as they don't expect to move Alaska oil down it," he told the Associated Press.

Foothills spokesman Rutherford said that if Alaska gets federal permission to export its oil, "there would be no need for this line. We view this as an alternative to exports," he said.

However, "it would be terrific if the state got temporary export permission until this line was built," Rutherford said.

GRAVEL PROPOSES REPEAL OF OIL EXPORT RESTRICTIONS

Sen. Mike Gravel will urge Congress when it convenes next year to lift restrictions on the export of Alaska oil, aide Deming Cowles says.

Gravel introduced a proposal to allow exports as an amendment to the omnibus tax bill in the closing days of the last congressional session, but it was not formally debated on the Senate floor.

Gravel's proposal would impose three conditions before exports could take place:

-- At least half of the exported oil would have to be transported in U. S. flag (Jones Act) tankers to its foreign destination.

-- The Trans-Alaska Pipeline would have to be "operating at full capacity." (The amendment does not define "full capacity.")

-- Contracts for exports could be terminated if the country's oil supply were interrupted or seriously threatened.

Gravel said his approach "would provide the requisite incentive to the producers of North Slope oil to take the steps necessary to expand North Slope production from 1.2 to at least 2.0 million barrels per day, the ultimate capacity of the Trans-Alaska Pipeline System."

Allowing exports would be in the national interest, Gravel said, because it would increase the nation's oil production capacity, lessen the impact of a future embargo, and improve the balance of trade.

"Today, as much as 800,000 barrels of oil per day--or some 10 percent of our existing domestic production--are not being developed and produced because of the lack of marketing opportunities. If we produced and exported that oil, our balance of trade with Japan would improve by some $4.066 billion per year," he said.

Cowles said prospects for easing restrictions on exports have improved considerably since President Carter announced a year and a half ago he would not authorize exports of Alaska crude. "A spokesman for the administration told us in September that they were very favorably disposed toward the idea, but that politically they couldn't do anything with it this year. I expect that next year they'll be looking at it very seriously, as well as at some other proposals and modifications (to Gravel's amendment)."

Export debate in the next Congress may center on 1977 amendments to the Export Administration Act, which expire June 22, 1979. These amendments impose the most severe restrictions on the export of Alaska oil, although two other federal statutes also restrict exports. Cowles said he expects the Senate Banking Committee will begin hearings on the Export Administration Act in February or March.

It seems unlikely the Alaska congressional delegation will be united on this issue.

Rep. Don Young, a supporter of the 1977 "McKinney amendment" that would have categorically prohibited exports of Alaska oil, is still "steadfastly opposed to exporting the oil," said aide Rod Moore.

"For a number of reasons, Mr. Young feels it is better to keep Alaska's oil in the American market....If you can transport that oil by pipeline, the construction and operation of those pipelines will supply greater employment and greater benefits to the nation," Moore said.

DOE STUDY SHOWS BENEFITS OF EXPORTS

Lifting the ban on the export of Alaska crude oil could save the nation between $2 billion and $18 billion in the next decade, a draft Department of Energy study says.

The draft study, which is now being reviewed by Energy Secretary Schlesinger, was prepared by DOE's Office of Policy and Evaluation.

The economic benefits to the nation would vary, the analysis says, depending on whether a west-to-east pipeline is constructed, and whether lifting the ban encouraged additional domestic production.

"The analysis indicates that the efficiency gains (real resource savings) from lifting the export ban would be $2 - $8 billion (even if no additional production is brought on by lifting the ban). If lifting the ban also were to cause a production response of 1.0 MMB/D by 1990, the efficiency gains would increase by at least $2 billion," the report says.

"In addition, a significant production increase would restrain future OPEC price increases. The world price benefits to the U. S. of a 1.0 MMB/D increase for 1990 would save the U. S. $4 - $8 billion. As a result, with a significant production response, the increase in total benefits from lifting the ban would be $8 - $18 billion."

Alaska officials have maintained that the export ban significantly discourages additional North Slope production from known reservoirs and reduces the incentive to explore for new fields.

Lifting the ban would have the following effects, the study said:

-- North Slope producers would obtain higher after-tax profits on the sale of their crude;

-- The State of Alaska would obtain higher royalties, severance taxes and income taxes;

-- The federal government would obtain more income taxes and would obtain an import fee on every barrel imported to replace the North Slope crude shipped to Japan;

-- Foreign ship-owners would receive additional income for the transport of crude between Japan and the U. S. and between the Persian Gulf and the U. S.;

-- Domestic ship and pipeline owners would receive less income for the transport of crudes.

CONGRESSIONAL COMMITTEE ISSUES WEST COAST OIL SURPLUS REPORT

A recent report by the House Interior Committee indicates that lifting the ban on the export of Alaska oil is not high on Congress' list of ways to solve the West Coast oil surplus.

The committee report, prepared by Interior's Subcommittee on Special Investigations, urges expeditious construction of one of the overland pipelines proposed to ship Alaska North Slope oil from the West Coast to inland states. If none of the proposed projects has gotten beyond the planning stages by January, 1979, Congress should consider legislation to expedite construction, the report says.

The report also recommends that Congress give further consideration to the proposed Trans-Guatemala pipeline, which it calls "a viable proposal worthy of close attention in the months ahead."

The report labels exports or exchanges with foreign nations a "short-term" solution, along with shipment through the Panama Canal and limiting ANS production to the amount that can be consumed on the West Coast. The subcommittee said shutting-in ANS production would have to be "emergency in nature," and found no arguments to support this short-term solution.

As far as exports or exchanges, the subcommittee did not support or oppose them but said it found no reason to believe they would be allowed in the near future.

While the majority subcommittee report merely listed the pros and cons of allowing exports, a minority report strongly opposed them.

"We believe a temporary export or exchange of Alaska North Slope crude oil with foreign nations would be unwise at this time and most unwanted by the American people," the minority report said. "How can we speak of exporting our great domestic supplies at a time when our oil imports grow day by day?...Let us consider ways to move the Alaska oil within our borders, not ways to move it out."

The minority noted that even temporary exports "would cause irreparable harm to the solvency of the U. S. Panama Canal Company," which American taxpayers have underwritten through this century under the recent canal treaties. "Unless we are now ready to cover multi-million dollar deficits on an annual basis when the canal loses the keystone to its solvency--Alaska oil transport--we should disapprove the temporary export of Alaska North Slope crude oil," said the minority report, which was signed by Rep. Don H. Clausen of California, the subcommittee's ranking minority member.

The majority report listed five proposed pipelines and retrofitting of West Coast refineries as "long-term" solutions to the West Coast surplus. The report noted that all the proposals will require a construction period of at least two years from initial groundbreaking, and that environmental considerations will delay their operation even further into the 1980s.

Two pipelines no longer under consideration--Trans-Mountain and Kitimat--are "victims of this nation's and Canada's codified concern for its environment," the report said. The Sohio pipeline between California and Texas "continues to encounter enormous State (of California) environmental protection obligation requirements. Whether or not it will ever be approved for construction is anybody's guess at this time," the report said.

The Northern Tier proposal, which would extend 1,550 miles across Washington, Idaho, Montana, North Dakota and Minnesota, still lacks a final Environmental Impact Statement and "is so far away from completion that its viability may well depend on the success or failure of the other proposals," the report said.

SOHIO PIPELINE MOVES ONE STEP CLOSER

Voters in Long Beach, California, overwhelmingly approved a proposed oil terminal in the November elections, but three more obstacles to construction of the Sohio pipeline still remain.

The oil terminal referendum, approved by a vote of 61 percent to 39 percent, authorizes city and port of Long Beach officials to grant permits for Sohio to build a terminal to receive North Slope crude for shipment by pipeline to Midland, Texas, and the Midwest. Sohio reportedly spent $750,000 in its campaign to gain approval for the terminal, which was opposed by environmentalists.

The 1,000-mile pipeline would be able to carry 500,000 barrels of oil a day. About 800 miles of existing pipeline would be used in the project, and about 225 miles of new pipeline would be constructed. Construction of the oil terminal and new pipeline sections is expected to take about two years, once final government approvals are granted.

The company says it still must get favorable decisions on three matters before construction can begin:

-- The South Coast Air Quality Management District must approve Sohio's plan for offsetting air pollution created by the terminal.

-- Sohio is asking the California Coastal Zone Commission to amend the project's coastal zone permit and allow construction of oil storage tanks at pierside. The commission already has rejected this request, but Sohio plans to ask again.

-- The California State Supreme Court must decide whether the project's environmental impact report is adequate.

The Department of Energy, meanwhile, announced it has postponed construction of a 167-mile, government-owned crude oil pipeline between the Elk Hills naval petroleum reserve and the proposed Sohio pipeline system. DOE, citing uncertainties in Sohio's construction schedule, said no major expenditures will be made on the project during the next two years.

PRUDHOE ROYALTY GAS SALE STILL IN DOUBT

Natural Resources Commissioner Robert LeResche says the administration has not yet decided whether it will go forward with a Prudhoe Bay royalty gas sale next spring.

LeResche said he thinks a sale at this time would be "terrifically premature," considering the uncertainties surrounding the gas pipeline project, but he wants to discuss the matter with legislators and other state officials before a final decision is made. He recently asked the attorney general's office to draw up a draft contract for the sale.

The administration is under increasing pressure to sell the royalty gas and gas liquids this spring, particularly from people in Fairbanks.

A delegation from Fairbanks, led by Borough Mayor John Carlson, met with Hammond in Juneau recently to urge him to submit a contract for approval during the next legislative session.

LeResche angered a number of people in Fairbanks when he was unable to attend a borough-sponsored petrochemical seminar November 28. LeResche said the press of d2 business and attempts to keep President Carter from withdrawing lands under the Antiquities Act prevented his attendance.

"To put it mildly, the mood was definitely hostile," Andy Warwick, a member of the Royalty Oil and Gas Development Advisory Board, told the All-Alaska Weekly. Warwick also complained that LeResche had not called a meeting of the royalty board since May 19. According to press reports, some Fairbanksans fear that unless action is taken quickly, the state will lose out on petrochemical development by default.

The Department of Natural Resources last summer circulated a "general notice and solicitation" to 500 firms announcing that it intended to sell the Prudhoe royalty gas and gas liquids, with the sale tentatively scheduled to take place in March.

The draft contract prepared for LeResche would sell 80 percent of the Prudhoe Bay royalty gas for 20 years. All gas sold under the contract "shall be either processed or consumed within the boundaries of the State of Alaska," the draft contract says. "Buyer shall construct and operate, or cause to be constructed and operated, a facility for the in-state processing of the gas sold under this agreement."

The price for the gas would be at least the amount the state would have received by taking the gas in-value, and potential purchasers presumably would bid a variable number of cents above the in-value floor, the draft contract indicates. In addition, the contract says, if the federal government allows the costs of conditioning the gas to be added to the maximum ceiling price in the Natural Gas Policy Act, the price the royalty buyer pays will be increased by the amount of costs allowed.

LeResche said the legislature would be asked to approve the structure and terms of the contract before bidding takes place.

Don Wold, executive director of the state's Royalty Oil and Gas Development Advisory Board, said he agrees with LeResche that there is no big rush to sell the gas this year. "Whether we sell it this year or next is not important," Wold said.

Wold expressed concern, however, about the design of the North Slope conditioning plant set out in a study by the Ralph M. Parsons Co. The study was prepared for seven North Slope oil producers and 11 pipeline companies.

Wold said the conditioning facilities currently contemplated would use a large percentage of the gas liquids as field fuel rather than as exported products. If most of the liquids are used as fuel on the North Slope, they will not be available as feedstock for in-state petrochemical manufacturing.

"If you wanted a petrochemical industry in Alaska, you wouldn't select this design for the conditioning plant," Wold said. "The producers are flexible; they aren't locked in (to this design). But obviously they don't believe that petrochemicals are viable in Alaska, and since they don't believe it, it's an easier, simplier operation for them to burn the liquids on the North Slope....If someone were to convince the producers that petrochemicals are going to happen, I've found no evidence that they wouldn't be willing to change and produce the liquids."

In an October 24 memo to LeResche, Wold spelled out a number of actions that would help retain the option of liquids production, including:

-- Obtain an improved estimate of constructing an 18-inch liquids pipeline from Fairbanks to tidewater;

-- Request that Northwest Alaskan, in cooperation with a state consultant, estimate the cost of constructing an 18-inch liquids line from Prudhoe to Fairbanks;

-- Request that ARCO (coordinator of the Parsons study) estimate what changes would be required in the conditioning facilities should it become feasible to recover the maximum amount of liquids;

-- Request that Northwest estimate the economic impact on the gas pipeline should the liquids be removed;

-- Ask FERC what its position would be if the liquids were removed from the pipeline and retained in Alaska; and

-- Ask the Alaska Railroad to estimate the cost of moving the liquids from Fairbanks by rail.

Wold said he expects a preliminary report by the end of the year from Bonner & Moore Associates, which is under contract with the Department of Natural Resources to help the state promote development of a petrochemical industry. The report will address the economics of in-state petrochemical manufacturing. "With the numbers we have now," Wold said, "it looks very marginal."

PACIFIC ALASKA LNG PROJECT PROCEEDS; ALASKA'S RIGHT TO WITHDRAW COOK INLET ROYALTY GAS UNCERTAIN

Alaska would have difficulty withdrawing its Cook Inlet royalty gas for in-state use from fields supplying the Pacific Alaska LNG project if the Federal Energy Regulatory Commission follows the recommendations of its staff.

In a "reply brief" dated November 21, the FERC staff recommended that the commission not allow Alaska to switch from in-value to in-kind taking for royalties initially committed to the LNG project without first getting abandonment authority from FERC.

"Alaska has made absolutely no showing of in-state need for this gas in even the remote future. The condition suggested (by Alaska) amounts to a pre-granted abandonment of unknown quantities of gas, at unknown times, for unknown duration and for unknown purposes," the FERC staff said.

One of Alaska's main concerns in the federal regulatory proceedings on the proposed Cook Inlet LNG project has been to assure that it will be able to withdraw royalty gas for in-state use should the need arise in the future. Alaska has asked that FERC guarantee this right as a condition to its certification of the LNG project.

Alaska's ability to withdraw its Prudhoe Bay royalty gas from the proposed Alaska Highway gas pipeline is protected by Section 13(b) of the Alaska Natural Gas Transportation Act of 1976. The act states, "The State of Alaska is authorized to ship its royalty gas on the approved transportation system for use within Alaska and, to the extent its contracts for the sale of royalty so provide, to withdraw such gas from the interstate market for use within Alaska..."

The Pacific Alaska LNG project, which has been pending before federal regulators since 1974, would liquify gas from 19 Cook Inlet fields at a Nikiski plant for export to Southern California. About 400 million cubic feet of gas a day would be transported in LNG vessels to a terminal at Point Conception, California. LNG (Liquified Natural Gas) is naturally occurring methane transported in liquid form by tanker.

In a brief filed November 7, the state reiterated its position that it is willing to allow its gas to be exported to serve the needs of Lower 48 users until "a specific feasible use" develops in Alaska. Alaska insisted that its "right to take the royalty in kind is paramount to the producers' right to sell 100 percent of production to Pacific Alaska LNG."

Under the old Natural Gas Act, once gas is "dedicated" to interstate commerce, "abandonment" permission must be obtained from FERC before the gas can be withdrawn from interstate commerce. Alaska argued in its brief that the Natural Gas Policy Act of 1978, rather than the old Natural Gas Act, governs disposition of the Cook Inlet royalty gas.

Under the new Natural Gas Policy Act, Alaska argued, FERC no longer has authority to require abandonment if the gas was not committed or dedicated to interstate commerce on the date the new act took effect. The Cook Inlet gas in question has not been dedicated to interstate commerce, Alaska said, since no certificates have been issued and no gas has flowed in interstate commerce.

"The Commission is without jurisdiction to order the State of Alaska, at an appropriate time in the future, not to exercise its royalty rights vis-a-vis the producers and withdraw future supplies of Cook Inlet royalty gas from the interstate market without obtaining abandonment authority," the state said.

Alaska said FERC should certify the LNG project, as well as protecting the state's right to withdraw its royalty.

"Respecting Alaska's royalty rights will not endanger this project or adversely affect the interests of consumers. It will tend to enlarge the supply of gas for this project and make available to the Lower 48 States present and future Alaskan reserves from Cook Inlet. The public interest would be well served by certifying this project with full confirmation of Alaska's royalty rights," Alaska said.

The FERC staff, however, said Alaska's interpretation of the laws is erroneous, and concluded that Cook Inlet gas now under contract to Pac Alaska already has been "committed or dedicated" to interstate commerce. Since the gas already is committed, FERC retains its authority under the Natural Gas Act to require that the gas supply upon which the project relies is firmly committed to it, the FERC staff said.

Also, the FERC staff said, Alaska has failed to show that protection of its royalty rights "is in the public convenience and necessity." Alaska failed to show, despite a specific request from Staff Counsel in October, 1977, exactly how much natural gas it will need for its own use from Cook Inlet reserves, whether alternate fuels such as coal or electricity would satisfy those energy needs, and data on needs for in-state markets. "Mr. (Fred) Boness (deputy commissioner of Natural Resources), Alaska's only witness, failed to give even the most general projection of any in-state need at all during the life of the project," the FERC staff said.

The issue of state royalty rights is closely related to another issue--whether there is adequate gas in Cook Inlet to support the project. In order to supply 400 million cubic feet of gas a day to California for 20 years, Pac Alaska will have to obtain contracts for about 3.1 trillion cubic feet of gas. At present, the project has only about 800 billion cubic feet (including state royalties) under contract, or less than one-third of the amount needed.

The FERC staff recommended that the project's certificate not become final until 2.6 trillion cubic feet of gas has been dedicated to the project, and suggested that Pac Alaska be given one year to secure contracts for the necessary reserves. Pac Alaska should not be able to count Alaska's royalty share in the 2.6 Tcf unless it can show that Alaska has elected to receive its royalty interest in-value for the life of the gas supply contracts, the FERC staff recommended.

Pac Alaska's parent companies, which also have exploration subsidiaries, already have spent about $35 million looking for gas in Cook Inlet, and they have put up an additional $20 to $30 million in loans to producers for drilling in known fields. The companies plan to spend another $20 to $30 million on exploration during the next three years.

In response to charges that Pac Alaska is buying up all the known gas reserves in Cook Inlet, gas that Anchorage may need in the future, Pac Alaska spokesman Bill Cole responded: "We are putting up money to drill where there's never been any incentive to drill before. We are making the pie bigger. Except for Lower Cook Inlet, there was no exploratory drilling of any magnitude going on in Cook Inlet until we came along and put up real big money."

Cole also points out that Pac Alaska has been unable to get contracts for most of the proven uncommitted reserves left in the Inlet, and that most of the gas under contract to the project was found with Pac Alaska's money. He said he remains optimistic that Pac Alaska will find the gas it needs, although not within the one-year time frame suggested by FERC staff.

Final FERC hearings on a number of issues in the case are scheduled for early December, and a FERC administrative law judge is expected to make a recommendation on whether to certify the project next spring or summer. A decision by the full commission is not expected before late 1979, and that decision could be appealed to the federal courts.

The Pac Alaska project is sponsored jointly by subsidiaries of Pacific Lighting Corp. and Pacific Gas & Electric Co. (PG&E). The two parent companies also jointly sponsor the Pacific Indonesian project, which will import LNG from Indonesia to the same Point Conception terminal proposed for the Pac Alaska project. The economic viability of the Pac Alaska project depends on approval of the Pacific Indonesia project, a spokesman for Pac Alaska said.

In final Environmental Impact Statements issued recently for the two projects, the FERC staff concluded that environmental impact associated with the Alaska project would be limited. The LNG terminal at Nikiski would not have a significant environmental impact, and the risk associated with operation of the LNG ships is acceptable, the FERC staff said.

With respect to the California terminal, however, the FERC staff said Point Conception should be rejected primarily because it is near an active earthquake fault. The FERC environmental staff said Oxnard is the superior location for an LNG terminal facility, taking into account all environmental factors, including public safety.

Western LNG Terminal Associates (another joint subsidiary of Pacific Lighting and PG&E) originally proposed to build separate terminals at Oxnard for the Indonesian imports and in Los Angeles Harbor for the Cook Inlet gas. However, both sites were eliminated as possible terminal locations by California legislation requiring that the state's first LNG terminal be constructed in a sparsely populated area. In light of this legislation, Western Terminal asked the California Public Utilities Commission to approve a single terminal near Point Conception to handle gas from both Indonesia and Alaska. The California PUC has conditionally approved the Point Conception site, pending the outcome of future hearings on safety and environmental issues.

A major issue in the controversy over where to put the LNG terminal is whether California can assert jurisdiction to select and approve it. The FERC staff has argued that the California legislation intrudes into an area Congress has entrusted to federal regulation, thereby preempting state regulation. It is unclear how this matter will be resolved, short of litigation.

To complicate things even more, the federal Economic Regulatory Administration has jurisdiction over some aspects of LNG imports and exports, such as security of supply and effect on U.S. balance of payments, and must also approve the Pacific Indonesia project.

ALPETCO SELECTS VALDEZ FOR FACILITY SITE

Valdez, the city selected by Alpetco for its planned refinery and petrochemical complex, has adopted an ordinance that will require tankers arriving at the trans-Alaska oil pipeline terminal to burn low-sulfur fuel while in port.

The low-sulfur fuel ordinance, which was adopted 5-1 by the Valdez City Council December 5, requires tankers of more than 15,000 tons to use fuel with a sulfur content of less than .7 percent while pumping ballast tanks within the Valdez city limits. The ordinance takes effect January 1, 1982.

Valdez Mayor L. F. MacDonald said the new ordinance will be sufficient to offset pollution created by Alpetco's refinery and petrochemical facility. Without the ordinance or some other mitigating measure, Valdez likely would have violated federal air quality standards once the new refinery began operation.

Alpetco officials said the decision to select Valdez over Kenai for the refinery site was based primarily on economic factors, specifically a $20 to $30 million annual saving in shipping costs. Since the site about five miles east of Valdez is near the oil pipeline terminal, the company won't have to pay the extra cost of shipping the oil to Kenai.

Valdez has offered Alpetco essentially free city land for the plant site, and the city plans to issue tax-exempt Industrial Development Bonds to help finance docks, support facilities and pollution control devices.

The legislature last session awarded Alpetco a 27-year contract to purchase 85 percent of the Prudhoe Bay royalty oil. Under terms of the contract, Alpetco will become eligible to begin purchasing the oil in about a year and a half if it has obtained financing commitments for at least $1.5 billion and actually spent $100 million on the project.

A spokesman for the Department of Natural Resources said Commissioner LeResche expects to make a decision approving or disapproving the Valdez site by mid-January. A public hearing will be held in Valdez in early or mid-January.

Construction of the facility is not expected to begin before late 1980.

NATIVES PROTEST EXXON DRILLING AT DUCK ISLAND

Two native villages and the City of Barrow have filed suit in state and federal court in an attempt to stop exploratory drilling from a man-made gravel island in the mouth of the Sagavanirktok River, about 12 miles east of Prudhoe Bay.

If successful, the suits would have a chilling effect on oil and gas exploration and development all over Alaska, state officials say.

The state suit charges that the Department of Natural Resources committed procedural errors in approving the Duck Island Unit Agreement and a drilling permit. State Superior Court Judge Victor Carlson has denied the Natives an injunction in the case, thereby allowing drilling to continue until the case is decided.

"The uncertainty which would attach as a result of injunctive relief will effectively halt oil development in the State of Alaska," the state said in a brief opposing the injunction. A ruling for the plaintiffs "will result in a long-lasting and severe impact on Alaska's already weakened economy."

The leases in question were sold by the state in 1969 and bought by nine oil companies for more than $20 million. The companies formed the Duck Island Unit, which was approved by the Department of Natural Resources in August of this year, and designated Exxon as unit operator. The leases would have expired in September of 1979 unless oil drilling or production activities had begun.

"At issue here is our permitting procedure, and the ability of a lease-holder to exercise the rights he paid for," said Tom Cook, director of the Division of Minerals and Energy Management. "I'm worried about what this case does to future leases. If our permitting procedures and law can be successfully challenged, and multi-million dollar drilling operations halted, it's obvious what this does to the value of future leases."

Cook said unitization is an environmentally sound practice, since it allows one well to satisfy the drilling commitment. The alternative to unitization would be for each of the nine companies to proceed separately with drilling. "Unitization minimizes the environmental impact and allows the companies to assess the area without extensive drilling," Cook said.

The villages of Kaktovik and Nuiqsut, the City of Barrow, and two Native subsistence hunters charged in the suit that Exxon's activities are having an injurious effect on the bowhead whales and other marine mammals in the area. The Natives depend on the whales for food and "consider them vital to the continuation of their culture."

Donald Clocksin, the Alaska Legal Services attorney representing the Natives, told the Associated Press the suits represent "the opening shot in a major battle" against the Beaufort Sea lease sale scheduled for December, 1979.

State officials disagree with the Natives' contention that unitization amounts to a sale or disposal of interest in state lands and therefore requires public notice and other procedures.

Natural Resources Commissioner Robert LeResche said the procedural charges in the state suit are "frivolous," and the Natives "are just looking for technical ways to stop the drilling."

Some state officials believe, however, the Natives may have a much stronger case in the federal suit filed in U. S. District court against the U. S. Army Corps of Engineers and Exxon.

Federal District Court Judge James von der Heydt denied the Natives' motion for a temporary restraining order November 16. A hearing on their motion for a preliminary injunction was held December 7, but the judge has not yet ruled.

Ernst Mueller, commissioner of the Department of Environmental Conservation, has filed an affidavit supporting the Natives' charges that the Corps of Engineers violated federal law by issuing permits for Exxon to build the gravel island as a base for offshore drilling.

The federal Clean Water Act requires that Exxon present the Corps of Engineers with certification that its planned activity meets state water quality standards. Without the state certification, which was not issued in this case, the Corps of Engineers cannot legally issue permits to build such an offshore island, Mueller said in his affidavit.

Mueller's affidavit indicates the Corps of Engineers habitually ignores requirements for the state to certify proposed projects affecting water quality in Alaska.

INTERIOR DEPARTMENT CONSIDERS P.L.O. 82

The Interior Department is expected to decide in the near future whether the federal government will attempt to reclaim a large chunk of arctic Alaska under Public Land Order 82.

P.L.O. 82 is an executive World War II land withdrawal that reserved for military purposes all submerged lands north of the Brooks Range crest, an area that includes about 40 percent of the oil and gas at Prudhoe Bay and the entire arctic coastline out to the three-mile limit.

Although the land order was revoked in 1960, Interior has argued the state does not have title to the lands since the order was in effect at the time of statehood.

Tom Cook, director of the Division of Minerals and Energy Management, said Interior has written an opinion adverse to the state but was persuaded by state officials to reconsider. The opinion, Cook said, would have asserted that the federal government had title to all lands reserved under P.L.O. 82.

Deputy Natural Resources Commissioner Fred Boness, who participated in talks with Interior officials in early November, said, "The meetings didn't go well. I don't know what's going to happen. We have to be prepared to deal with any eventuality. I don't think the decision is going to be favorable."

Natural Resources Commissioner Robert LeResche said uncertainty over P.L.O. 82 is having an adverse effect on gas sales negotiations between North Slope producers and the pipeline companies building the Alaska Highway gas line. "The firms are not selling the gas; they can't as long as there's any question about who owns it," LeResche said.

P.L.O. 82 also could disrupt plans for the joint state-federal Beaufort Sea lease sale scheduled for December of 1979.

"The spector of P.L.O. 82 creates a lot of uncertainty," said Cook. "The companies will be reluctant to bid if they think title to the land is in doubt. Who wants to buy litigation? I don't think we should hold the (Beaufort) sale if this is not resolved."

FEDERAL GOVERNMENT REVISES OCS LEASING SCHEDULE

Eleven of 22 areas proposed for inclusion in the federal government's new OCS leasing schedule for 1980-85 are in Alaska.

The federal government is in the process of preparing a leasing plan for the next five years under recent amendments to the OCS Lands Act, and is soliciting comments from affected states. The state's response on the preliminary proposal will be completed in early December, said Craig Lindh of the Division of Policy Development and Planning.

Areas in Alaska proposed for sale include Cook Inlet, Gulf of Alaska, Kodiak, Southern Aleutian Shelf, Bristol Basin, St. George Basin, Navarin Basin, Norton Basin, Hope Basin, Chukchi Sea and Beaufort Sea. Dates for the proposed sales have not yet been published.

The Secretary of the Interior won't approve the final plan until January, 1980. During the next year, Interior will hear public comment and make revisions in the plan, which will be submitted to President Carter and Congress next November.

A decision to proceed with any specific sale on the schedule will be made only after all requirements of the OCS Lands Act, the National Environmental Policy Act and other statutes are met.

Interior is proceeding with plans to sell leases in the eastern portion of the Gulf of Alaska in June, 1980. In late October, Interior announced selection of almost two million acres for environmental study and possible inclusion in the sale.

This would be the second OCS sale in the Gulf of Alaska. The first, which was in April, 1976, and brought bids of $560 million for about 410,000 acres, was recently declared valid by D. C. Circuit Court of Appeals in response to environmental challenges raised by the state. Alaska challenged the sale on grounds it violated the National Environmental Policy Act.

The state administration, meanwhile, is preparing its own five-year leasing plan under terms of a new oil and gas leasing law adopted by the legislature last session (HB 854).

The new law requires that the Commissioner of Natural Resources submit a plan to the legislature by the 15th day of the next session covering all areas to be leased in 1979 through 1983.

Tom Cook, director of the Division of Minerals and Energy Management, said he will recommend two changes in the 1979 schedule announced by Gov. Hammond last March. Cook said he will recommend that the Copper River Valley sale be deleted, since the state has little land available for lease in the area and industry has shown little interest. He said

he will recommend that the Susitna Valley sale be postponed until after the December Beaufort sale to allow his staff adequate time for preparation.

"Susitna would be a 'limited acreage' sale, which could be held without extensive pre-sale procedures, studies, notice and opportunity for public comment," Cook said. "However, it should be obvious after Point Thomson (which was canceled by Hammond in September) and the Duck Island suit that it's unwise to proceed on that basis."

STATE FAVORS JOINT BIDDING FOR BEAUFORT SALE

The state will urge the Interior Department to waive restrictions for the 1979 Beaufort Sea lease sale that prohibit major oil companies from submitting joint bids.

"In the case of the Beaufort Sea, we'd like to see the secretary waive restrictions on joint bidding," said Tom Cook, director of the Division of Minerals and Energy Management. "We believe this would enhance the number of offers, the amounts of the offers and minimize risk among the parties. This is a high-cost, high-risk area and it cannot be as effectively developed or explored if joint bids are prohibited," Cook said.

OCS Lands Act Amendments of 1978 specify that the Interior Secretary may waive the joint bidding ban if he determines that exploration and development will have an extremely high cost and will not occur unless an exemption is granted.

At the request of Chevron USA, the Interior Department scheduled hearings on the matter December 5 in Anchorage and December 8 in Washington, D.C.

ECONOMISTS SEE "HARD LANDING," FAVOR DIRECT DISTRIBUTION OF OIL WEALTH

Many of Alaska's leading economists think the state will face a fiscal "hard landing" sometime in the next 10 to 15 years.

Thirty of the state's leading economic model builders and users, who attended a Symposium on Economic Model Building in Alaska October 21 and 22 in Anchorage, also generally agreed it would be desirable for the state to distribute some of its oil wealth directly to its citizens.

Sponsored by the Legislative Affairs Agency, and funded out of money allocated to gas pipeline financing studies, the symposium provided a look at the strengths and weaknesses of the models in operation in the state today.

The smaller revenue and expenditure forecast models and the petroleum revenue tax model, as Dave Knudsen remarked, were "not built to make

predictions." They were, however, all considered to be useful analytical tools. The larger models include those of the Department of Labor, the Department of Commerce and Economic Development (CED), and the MAP model of the University of Alaska's Institute of Social and Economic Research. "Use of these models needs to be carefully tailored to their capabilities," commented David Reaume of CED, particularly when one is looking more than two years into the future.

The only large, long-term policy testing model available in Alaska, the MAP model, was recognized to have both strengths and weaknesses. On the plus side, this comprehensive regional model can in theory answer many of Alaska's major policy questions. Furthermore, its operators will change parts of the model that caused problems in the past, such as its rules for internally generating state government spending rates. The symposium generally agreed that changes of this kind, together with a greater anticipation of user interests, would eliminate the confusion that developed last year when the MAP model was employed to analyze the ALPETCO proposal. Almost all conference participants agreed that an investigation of the impacts of gas line construction along the lines of the ALPETCO study is necessary and desirable.

A discussion led by Arlon Tussing, Lee Gorsuch, and Gregg Erickson reviewed future modeling needs. Impacts from construction of a gas pipeline, use of the Permanent Fund to develop renewable resources, and use of the capital account to pay cash for new buildings were identified as topics needing additional analysis.

On the fiscal question there was complete agreement, based on quite independent analysis, that the state likely will face a "hard landing" when the Prudhoe Bay oil finally stops flowing. More stringent fiscal control will be needed for a soft landing in the 1990s. Several participants noted that there appear to be few economic alternatives to generate the magnitude of revenue needed to cushion the landing.

The group also discussed methods to reduce the annual spending pressure placed on the legislature, including implementation of constitutionally imposed spending ceilings and distribution plans such as Alaska Inc.

The economists agreed that some form of distribution plan, in spite of major "leakages" that federal taxes would impose, would maximize benefits from the oil wealth and might be the only successful way to curb state spending growth. The degree of unanimity on this was unexpected. Although several economists said vested interests of the present government fiscal structure eventually would defeat the plan, almost all supported it in concept.

HAMMOND WILL ASK FOR SUSITNA APPROPRIATION

In an attempt to keep the controversial Susitna hydroelectric project on track, Gov. Jay Hammond announced recently he will seek a $7 million legislative appropriation to provide guarantees for studies on the project.

The massive project, promoted as a way to assure adequate electricity for Alaska's "rail belt," would involve construction of two dams on the Susitna River and 365 miles of transmission line. The project is now estimated to cost $2.7 billion in today's dollars, according to Eric Yould, executive director of the Alaska Power Authority.

The project will require a four-year "Phase I" study, which will examine environmental, economic, social and engineering concerns. Phase I studies, estimated to cost at least $25 million, will be conducted by the U. S. Army Corps of Engineers.

Legislation that would have provided federal guarantees for the Phase I studies died in the waning hours of the 95th Congress. It has been widely reported that the House of Representatives failed to approve the measure in retaliation against Sen. Mike Gravel's action killing the d2 lands legislation, although Gravel aide Jerry Gauche says the House action had nothing to do with d2.

The federal legislation would have amended the Alaska Hydroelectric Power Development Act of 1976, and would have provided that the federal government reimburse the Alaska Power Authority for the cost of Phase I studies if the project turned out to be infeasible.

The state legislature last session approved a resolution (Legislative Resolve No. 45) authorizing the Alaska Power Authority to fund the Phase I studies through the sale of revenue bonds, but this authorization was made contingent on passage of the federal legislation.

The $7 million appropriation sought by Hammond would provide guarantees for the sale of revenue bonds sufficient to cover the first year of the four-year studies. Yould said recent estimates indicate the first year of studies will cost $8.2 million, and he will recommend that the governor request the higher amount.

Gauche said Gravel will try again to get Congress to approve the legislation providing federal guarantees early in the next session.

"There is a certain risk to the state if this appropriation is approved," Yould said. "If Gravel never gets his legislation, the state will be out $8.2 million and will have to come up with additional money to complete the studies....However, Gravel has told me he thinks he can get this legislation early in the next session. I wouldn't be suggesting that the state make this appropriation to the Power Authority if I didn't think he could produce."

Hammond said he would request the state guarantees because "I believe it important to keep this feasibility study on schedule to avoid delays and increased construction costs. We need this information to determine whether the Devil Canyon project is environmentally and economically feasible. We want our decision based on fact, not guesses."

Even if the legislature or the Congress provides guarantees for sale of the revenue bonds, two other hurdles must be cleared before the Phase I studies can begin.

First, the U. S. Army Corps of Engineers must receive permission to participate in the study from the Office of the Chief of Engineers and the Office of Management and Budget in Washington. "OMB is standing in the way of Susitna right now," Yould said. "They have not authorized any new (water resource project) starts since Carter took office."

Second, access to the Susitna land to perform the studies will require permits from the Bureau of Land Management and agreements granting access from the Cook Inlet region and village corporations.

STATE ENERGY POLICY COMMITTEE ADOPTS POLICY GUIDELINES; DEVELOPS STRATEGY FOR IMPLEMENTATION

The state should study the costs, risks and benefits of contracting for exploratory drilling for oil and gas and obtaining additional geological and geophysical data, the State Energy Policy Committee has recommended.

The committee, meeting in Juneau December 6, decided to seek funds from the next legislature to study whether the state should invest money to obtain more extensive information about the resource potential of lands before leasing them for resource development. The study would be conducted jointly with the Department of Natural Resources.

The committee, chaired by Rep. Bill Miles, includes members of the legislature, administration and public.

At an Anchorage meeting November 29, the committee approved "policy guidelines" for the development and management of the state's energy resources, energy conservation and planning for in-state power development. Policy guidelines on the disposition of state royalties, which closely parallel the present policies of the Royalty Oil and Gas Development Advisory Board, were adopted by the committee at the December 6 meeting.

With general energy policies adopted, the committee then considered and adopted a number of ways to implement them, including:

-- In order to "encourage the development of economically viable renewable energy resources for in-state use," the committee decided to seek a change in Alaska law giving tax breaks (expensing of intangible drilling expenses and cost depletion) for geothermal

wells. Congress recently adopted such a change in federal law in the Energy Tax Act of 1978.

-- In an attempt to "insure the orderly and timely development of energy resources, taking into consideration resource marketability," the committee decided to study the possibility of enacting a uranium leasing law.

-- In order to "insure a fair return to the people of the State for conveyance of state-owned energy resources," the committee will recommend an increase in coal royalties.

-- In order to "protect the environment when this is consistent with other provisions of the State Energy Policy," the committee plans to oversee development of state coal mining regulations under the federal Surface Mining Control and Reclamation Act of 1977.

The committee also wants to assure coordination of the state's environmental impact assessment process, to avoid overlap between state and federal agencies, for all energy projects that significantly affect the human environment.

-- In order to "encourage and facilitate the implementation of energy conservation measures, for all in-state energy use," the committee will look into the fiscal impact of increasing state tax credit amounts and limits for residential fuel conservation credits. State law currently allows a tax credit of 10 percent, with a $200 limit, for insulating homes and installing alternate sources of power generation, such as wind, tidal, solar or geothermal. The new federal Energy Tax Act provides a 15 percent credit, with a $2,000 limit, for the costs of installing alternate power sources in homes.

The committee also wants to expand the authority of the Alternate Power Resource Revolving Loan Fund to allow loans for capital expenditures for energy conservation improvements.

The committee also suggested that state funds be used to supplement federal weatherization programs, if additional money is needed for administrative and labor costs.

The committee decided that statewide lighting and thermal efficiency standards should be adopted, with local communities having enforcement responsibility.

-- In order to "encourage the optimal use of exhaust heat," the committee wants to require, as a condition of using state royalties, that any baseload plant be a combined cycle unit, using waste heat from a gas or coal turbine to run a steam plant. The committee will look into requiring the efficient use of waste heat for any large industrial facility or pipeline.

-- In order to "assure coordination of State and Federal responsibility in planning for in-state energy needs and the development of in-state energy projects, and to avoid duplicative and overlapping effort," the committee will seek legislation to require the Division of Energy and Power Development "to give equal consideration to all types of power generation, which are technologically feasible to promotion of efficient fuel and facility use, consistent with energy conservation goals, and achievement of the lowest reasonable costs" in developing a long-range plan for the state.

-- In order to "encourage the availability of energy to all people of the state at the lowest possible rates, consistent with good management practices," a liaison group chaired by Rep. Leo Rhode recommended that the Reserve for Energy Facilities Development account be used by the Alaska Power Authority to help finance construction of smaller hydroelectric projects.

The reserve acount, established last session by Chapter 168 SLA 1978, will receive 5 percent of the state's mineral lease bonuses, rentals and royalties, and will be subject to annual appropriation of the legislature.

Suggestions for implementing policies on royalty disposition will be considered at the committee's next meeting, which has not yet been scheduled. The committee's final report is due by January 31, 1979.

ALASKA PIPELINE COMMISSION CONSIDERS "ALLOCATION OF SERVICE" FOR TAPS

The Alaska Pipeline Commission (APC) took testimony at a November 28 hearing in Fairbanks on whether four of the eight Trans-Alaska Pipeline carriers should be allowed to limit the amount of oil they carry for North Pole Refinery.

Last summer, BP Pipelines, Mobil Alaska Pipeline Co., Phillips Alaska Pipeline Corp. and Amerada Hess Pipeline Corp. filed initial tariffs for intrastate oil shipment. Under these initial tariffs, North Pole Refinery would have been charged as if its oil had traveled all the way to Valdez, even though its oil comes out of the pipeline near Fairbanks. On September 20, the commission suspended these initial tariffs and set interim, distance-related rates (about 60 percent of the full tariff) for delivery at Fairbanks. The interim tariffs do not take effect until mid-December.

The commission earlier set permanent, distance-related tariffs to Fairbanks for the other four carriers--Sohio Pipe Line Co., Union Alaska Pipeline Co., Exxon Pipeline Co. and ARCO Pipe Line Co.

BP, Mobil, Phillips and Amerada Hess have until February 1 to let the commission know whether they want a full hearing on their intrastate tariffs, a regulatory process already completed for Sohio, Union, Exxon and ARCO.

The intrastate tariffs to Fairbanks vary from $3.63 for ARCO to $3.87 for Amerada Hess. The average to Fairbanks for all eight companies is about $3.71, while the average tariff to Valdez is about $6.20.

The initial intrastate tariffs filed by BP, Mobil, Phillips and Amerada Hess also included special rules that limited the amount of intrastate oil they would carry. Specifically, the special rules limited each carrier's intrastate obligation to the percentage of pipeline capacity owned by that carrier.

The APC suspended the special rules at the same time it suspended the initial tariffs, but set a public hearing on the propriety of the special rules for November 28. Post-hearing briefs will be accepted until late January, so the commission will not decide the issue until February, at the earliest.

Under state law, the APC can "allocate service" over the pipeline, or impose a scheme for distribution of intrastate shipments among carriers.

Under law TAPS is a "common carrier" pipeline and must accept for transportation oil "tendered" (offered for shipment) to it without discrimination. TAPS operates like eight separate pipelines, with each carrier controlling an amount of space in proportion to its ownership share. If more oil is offered to a carrier than it can accommodate, it will reduce the amount of each tender by an equal percentage. This is called "prorationing."

Some of the companies apparently want to limit the amount of intrastate oil they are required to carry for economic reasons, since they make less money when oil comes out at Fairbanks and their downstream portion of the pipeline is less than full. North Pole Refinery, the only intrastate takeoff along TAPS, ships about 25,000 barrels of oil a day, of which about half is returned to the pipeline after some processing.

Lloyd Pernela of Earth Resources Company of Alaska, which owns North Pole Refinery, said the company has been unable to get all its oil shipped because until recently only four of the carriers (Sohio, Union, Exxon and ARCO) accepted intrastate shipments, and some of North Pole's oil was bumped by prorationing. A complaint by North Pole in July led to the filing of the initial intrastate tariffs by the other four companies. North Pole was 5,000 barrels short several days in September, Pernela said, and is still falling short some days because the new, lower tariffs for BP, Mobil, Phillips and Amerada Hess do not take effect until mid-December.

"We hope the APC will throw out the special rules," Pernela said. "To deny us the ability to tender crude to common carriers is gross discrimination."

The APC staff, in a recent brief, recommended that "the special rules included in the tariffs of Mobil, BP, Phillips and Amerada Hess be rejected and that allocation of service among intrastate carriers not be ordered by the commission. In lieu of allocation and the special rules,

it is the staff's recommendation that a coordinated tender schedule be established whereby each shipper is given an opportunity to receive regular information regarding transportation availability."

Jim Williams, executive director of the APC staff, said Earth Resources and the pipeline companies agreed at the Fairbanks hearing that they do not want the commission to allocate service.

PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

HALLORAN

STATE OF ALASKA
THE LEGISLATURE

POUCH Y · STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

LEGISLATIVE AFFAIRS AGENCY

ENERGY BACKGROUND REPORT FOR LEGISLATORS

No. 4 February 1, 1979

CONTENTS

	Page
Oil Surplus	
Prospects improve for Mexico-Japan-Alaska oil exchange....	1
Minnesota rejects Northern Tier pipeline.....	4
State analysis criticizes Foothills proposal.....	5
Leasing	
Administration intends to hold lease sales.....	6
Interior issues decision on PLO 82.....	12
Alaska urges Interior to postpone proposed OCS sales.....	14
Interior calls for nominations in Lower Cook Inlet.....	15
Gas Pipeline	
Schlesinger suggests federal loan guarantee for Alaska Highway pipeline.....	15
Federal leadership needed to break gas pipeline impasse...	22
Royalty Oil and Gas Development	
Developing an in-state petrochemical industry requires state action.....	24
Valdez expected to win approval as site for ALPETCO.....	30
Revenues	
OPEC price increase boosts state revenues.....	30
Alaska oil prices expected to rise on West and Gulf coasts.....	31
Exploration and Development	
d-2 outcome will affect oil exploration.....	32
Carter proposes halt to exploration in NPRA.....	32
Kuparuk field to be developed.....	33
Cook Inlet gas discovery announced.....	34
Other	
Mexican oil and gas are competition for Alaska.....	34
Hammond requests Susitna appropriation.....	38
Kelso describes plan to broaden capital ownership.....	39
Hammond appoints oil and gas conservation commissioners...	42

-- Compiled by Kay Brown, Policy Analyst --

AGO 532575

Oil Surplus

PROSPECTS IMPROVE FOR MEXICO-JAPAN-ALASKA OIL EXCHANGE

Mexican officials have "agreed in principle" on the terms of a contract to implement the proposed royalty oil exchange between Mexico, Japan and Alaska, Natural Resources Commissioner Robert LeResche says.

LeResche, who made a second trip to Mexico in late January to continue talks on the swap, said a formal contract won't be drawn up until President Carter approves the idea.

Although the White House has not yet agreed to put the swap on the agenda for discussion between President Carter and Mexican President Lopez Portillo when the two leaders meet in mid-February, LeResche said he is optimistic the matter will get attention. "We're pulling out all the stops to get it on the agenda," he said. "Portillo is going to request it; the governor is calling (Trade Ambassador Robert) Strauss and Carter personally."

The points agreed on by Mexico, LeResche said, include:

-- Alaska will deliver North Slope crude to the Pemex (the Mexican national oil company) account in Japan. Pemex will deliver Mexican crude to Alaska at Mexico's East Gulf Coast. Alaska intends to assign its rights and obligations of the contract to a third party--a major oil company or trading company.

-- The swap would not begin before June, 1979.

-- The volume will be 100,000 barrels per day.

-- Mexico will receive the "present prevailing price" for Mexican crude, recently raised to $14.10; the price term will be renegotiated every three months. LeResche said the state did not offer Mexico any price advantage for its participation. He said there are non-price advantages in the deal for Mexico, such as earlier trade and greater bargaining leverage with Japan.

-- Pemex will select the Japanese firm to participate in the swap.

-- The contract may be terminated at any time by the U.S. government if American petroleum supplies are interrupted or seriously threatened by world events, or if North Slope or Pemex production diminishes due to force majeure.

LeResche said he explained to the Mexicans that the deal is likely to face political opposition in the United States and "warned them not to get their hopes up falsely."

Obstacles still remain

Alaska officials would like to get Sohio as the state's middleman to be responsible for day-to-day operations such as arranging tankers and

taking delivery. Sohio has not yet agreed to participate, although Sohio Chairman Alton Whitehouse, Jr., recently said he strongly favors the general idea of exporting North Slope crude. The administration has hired Stuart Myar, a former marketing vice president for Sohio, to assist in working out arrangements.

Alaska also will ask Sohio to share with the state some of the profits it will make if the deal is approved. As the company suffering most from the West Coast oil surplus and the only company unable to market the bulk of its North Slope oil on the West Coast, Sohio would benefit either from approval of the state royalty oil swap or from a general lifting of the export ban.

"We're going to ask them to absorb some of the costs (of arranging the royalty oil swap) or to give us a premium," LeResche said. "They're clearly worse off without the swap than they are in having the swap and sharing some of the benefits with us. Besides, as a good corporate citizen of Alaska, Sohio won't wish to be the one to kill this deal when it's so much to our benefit." LeResche said he would formally approach Sohio with the idea "as soon as we get firm numbers showing the tremendous profit they're going to make."

Lack of firm figures on several critical points (such as the value of North Slope oil in Japan) makes it impossible to precisely calculate at this point how much money will be saved in transportation costs. LeResche said the saving could be anywhere from 1¢ to $2. "We honestly don't know yet," he said, but "we've got people working on it."

Another potential problem is that all Mexican production already has been committed through 1979, LeResche said. However, there are several possible solutions -- some of Mexico's customers might not renew contracts; a "paper" arrangement could be worked out; Mexico might increase production; or the process of presidential and congressional approval combined with the requirement for six-month notice to producers before in-kind taking might delay the deal to the end of the year.

The biggest immediate obstacle is winning the endorsement of President Carter. "I won't be surprised if Carter does approve it, but I won't be surprised if he doesn't either. But we're getting more optimistic every day," LeResche said.

Governor Hammond, Attorney General Avrum Gross, LeResche, State Representative Bill Miles and legislative consultant Arlon Tussing met in Washington with Department of Energy and White House officials in mid-January and came back encouraged that the administration will support the proposal.

Even with Carter's support, the deal won't be assured until it has been approved by Congress.

An association representing U.S. maritime interests, who stand to lose business if Alaska oil is allowed to be exported in foreign tankers, reportedly has begun an intensive lobbying campaign against the proposal in Congress. "They apparently are quite alarmed about it," one Washington lobbyist said.

Odds Improving

Energy Secretary Schlesinger, in a recent appearance before the Senate Energy Committee, said he believes congressional opposition to the export of Alaska oil may be diminishing. "For the past several months, we have tried to soften congressional resistance to exports. The climate may be better now than 18 months ago," The Anchorage Times' Washington Bureau quoted the secretary as saying.

Senator J. Bennett Johnston, a democrat from Louisiana, told Schlesinger that when restrictions imposed by the Export Administration Act expire in June, "it would be in the national interest for the President to go ahead and allow Alaskan exports. After all, we're talking about our balance of payments."

Senator Henry Jackson of Washington, chairman of the Senate Energy Committee, called the West Coast oil surplus "terrible and outrageous."

"We have only begun to tap the vast energy resources of Alaska," Jackson said. "In no area has public and private indecision and lack of cooperation between the public and private sectors been more prevalent. The time has come to make the decisions on exchange arrangements and transportation systems that will bring new supplies of Alaska's oil and gas to markets..." Jackson also called for a vigorous exploration program on the North Slope and expansion of the pipeline to its full capacity.

Since most of the opposition is expected to come from House members who voted for the trans-Alaska oil pipeline after being assured the oil would be used solely in this country, Representative Don Young's recent endorsement of the swap, although reluctant, may help overcome some opposition in the House. Although he is still "morally and philosophy-wise opposed" to exporting Alaska oil, Young said he would support a swap if the increased revenue to the state goes to the permanent fund. Young had previously opposed any swap arrangement. Hammond praised Young's "statesmanlike decision which will have an important influence in Congress."

LeResche said it now appears the Carter administration will wait until June, when the Export Administration Act amendments expire, before sending the proposal to Congress. "They prefer not to raise it when a one-house veto is possible," LeResche said. "The President will be the one to win or lose in Congress, so it's their strategy, not ours."

The New York Times, citing the need to encourage domestic production on the North Slope, endorsed the royalty oil swap with Mexico and Japan in a January 21 editorial.

Officials of the American embassy in Japan conveyed their tentative approval of the idea to Lt. Governor Terry Miller when he visited Tokyo in December.

At a December 14 meeting, the Western Interstate Energy Board approved a resolution offered by Alaska urging President Carter to approve the royalty oil swap. The resolution also included support for the foreign exchange of California state-owned royalty oil.

MINNESOTA REJECTS NORTHERN TIER PIPELINE

The Minnesota Energy Agency recently denied a certificate of need for the 75-mile Minnesota section of the proposed Northern Tier pipeline, which would carry Alaska and imported oil inland from Port Angeles, Washington.

The agency's director said he denied the certificate based on estimates that Northern Tier would not have a big enough crude oil market to make the project financially feasible. The certificate is required by Minnesota law before major energy facilities can be built.

A spokesman for Northern Tier Pipeline Company called the agency's denial a major setback, but said the company would not abandon the project. The agency's decision can be appealed in state court.

The $1.6 billion, 1,557-mile pipeline had been planned to terminate in Clearbrook, Minnesota.

Agency Director John Millhone said the decision might be reversed if President Carter selects Northern Tier under the new Crude Oil Transportation Systems law, if Northern Tier gets enough commitments from shippers for moving crude through the line, or if another proposed pipeline, the Northern Pipeline, isn't built in Minnesota.

The Northern Pipeline would carry oil from Wood River, Illinois, to the Minneapolis-St. Paul area. Under this proposal, oil from the Gulf Coast, including Alaska oil, would be brought by barge up the Mississippi River to Wood River.

Millhone said Northern Tier needs to ship 540,000 to 600,000 barrels a day to make its proposal economic. However, he said, current estimates suggest a shortage of only 68,000 to 100,000 barrels a day in northern tier states by 1980, rising to 485,000 barrels a day by the year 2000 as Canadian supplies are cut back.

A recent study for the Northern Tier Pipeline Company suggested that only 140,000 barrels a day of North Slope crude can be accommodated in northern tier state refineries.

Despite its problems with the eastern end of the line, Northern Tier may have come up with a way to head off environmental opposition at the western end. The company is considering a routing change that would eliminate tanker traffic in Washington State's Puget Sound, The Oil and Gas Journal reported January 15. The new proposed route, partially on land and partially under water, also would allow the line to serve four refineries on northern Puget Sound.

Most Alaska officials familiar with the surplus issue favor as solutions foreign exchanges of Alaska oil and conversion of West Coast refineries over any of the proposed pipelines.

A study recently conducted by Battelle Northwest gave the following estimated wellhead prices based on current prices and assuming a 62¢ per

barrel field cost and a TAPS tariff of $6.16 per barrel:

West Coast via Tanker	Houston via Panama Canal	Houston via PACTEX	Chicago via Northern Tier	Chicago via Foothills
$5.17/B	$3.11/B	$4.96/B	$4.84/B	$4.10/B

STATE ANALYSIS CRITICIZES FOOTHILLS PROPOSAL

The proposal to construct a major oil port at Skagway and oil pipeline into Canada appears to have major environmental drawbacks and little economic advantage for Alaska, a preliminary state study concludes.

The 500,000 barrel per day pipeline was proposed by Foothills Oil Pipe Line Ltd. of Canada and Northwest Energy Company of Salt Lake City as a way to move surplus Prudhoe Bay oil inland to the midwest. The companies in December filed formal application with the Interior Department under Title V of the Public Utility Regulatory Policies Act of 1978, which establishes an expedited federal process for selecting one or more pipelines to alleviate the West Coast oil surplus and an oil shortage in northern tier states.

"From the standpoint of revenue, there seems to be a consensus that none of the pipeline alternatives are particularly attractive if the West Coast oil surplus is alleviated either through changes in refinery capacity or exports of ANS crude oil. The cost figures supplied by Foothills are viewed with skepticism, and if any revision occurs, it will likely increase the transportation costs of the Foothills proposal. There will be a corresponding decrease in wellhead value and revenue to the state," said the preliminary report, which was written by the governor's Division of Policy Development and Planning based on analysis by eight state departments.

"The environmental risks of large tanker traffic in Chatham Strait, Lynn Canal and Taiya Inlet would be considerable. Many resources of great value (commercial salmon catches alone are worth more than $13 million annually) to Southeast Alaskans would be exposed to the threat of major oil spills," the report said.

"Given the uncertainties, there doesn't appear to be any persuasive argument at this time for the State of Alaska to favor construction of a crude oil pipeline from Skagway into Canada. In a way, Alaska's perspective is similar to that of Canada's in weighing the Kitimat pipeline proposal -- we Alaskans are being asked to bear most of the environmental risks while most of the benefits accrue elsewhere," the report concluded.

The cost of moving oil through the Foothills line would be about 4.6¢ per barrel per 100 miles, based on construction costs estimated by Foothills. The state report, noting that the Trans-Alaska Pipeline moves oil at about 77¢ per barrel per hundred miles, said the Foothills construction cost estimates appear unrealistically low.

Skagway, the Southeast Alaska community where most of the construction activity would occur, probably would be polarized by the pipeline, the report said. About 800 to 900 people would be employed in Skagway during construction of the oil port and pipeline and about 300 to 500 after construction, the report estimated. Skagway's general population would increase between 1,100 to 1,300 during construction and between 400 and 700 afterward.

Foothills spokesman Ron Rutherford said he was "surprised and disappointed at their conclusion that our project doesn't do much for the state...I realize there are environmental objections, but any port anywhere on the West Coast will have environmental disadvantages."

Rutherford said the Foothills project does improve wellhead values and state revenues when compared with the current arrangement of shipping Alaska oil through the Panama Canal to the U.S. Gulf. "I understand that exports are better from the state's perspective, that we're secondary to exports," he said.

An analysis by Battelle Northwest indicates that Alaska oil delivered to Chicago via the Foothills pipeline would have a wellhead value of $4.10 a barrel, compared to a wellhead of $3.10 a barrel for oil delivered to Houston through the Panama Canal.

Rutherford said the Foothills proposal should not be compared with the Alyeska experience, since much of the TAPS line had to be built above-ground due to permafrost while the Foothills line would be buried and conventionally constructed.

Leasing

ADMINISTRATION INTENDS TO HOLD LEASE SALES

The Hammond administration says it fully intends to hold every one of the 15 oil and gas lease sales on its new five-year schedule, including the Beaufort Sea sale set for December, if the federal government approves exports of Alaska oil.

Natural Resources Commissioner Robert LeResche told a joint meeting of the House and Senate Resources Committees January 31 that the state's commitment to hold the Beaufort Sea lease sale on schedule will be reconsidered "sometime this summer on the basis of whether they allow exports or not."

If the state receives permission to export or exchange Alaska oil, "we will hold (the sale) in December of '79," LeResche said. But if it's unclear whether export permission will be granted, "we could well delay or cancel it for that reason." He said the state would be "crazy" to hold the sale if export permission is denied, and pointed out that this stance "is causing some consternation in Washington."

When pressed on whether the administration actually would cancel the sale if the situation is not resolved by summer, LeResche said it would be a "difficult judgment call" and not an "easy yes or no."

LeResche also said "unforeseen legal and environmental problems or local objections" might alter the schedule.

In submitting the five-year leasing program as required by the new leasing law (HB 854) passed last session, LeResche said the future rate of leasing will be predictable, constant and moderate. The administration wants to promote orderly development, minimize environmental and social impacts, maximize revenues and establish incentives for the oil industry to remain healthy and stable in Alaska, he said.

Industry reaction to the leasing plan was generally favorable. "I think it's upbeat," one oil lobbyist said. "They're expressing an optimistic tone to which we're unaccustomed."

The statute does not require any legislative action on the five-year program, but LeResche suggested that "the legislature is clearly the perfect vehicle" for public comment on it.

The plan put forth by the administration listed the following areas and dates for sales:

1979 - July	Copper River Basin (exempt acreage sale) 1/
- December	Beaufort Sea (state-federal sale)
1980 - Early	Relinquished tracts on Arctic Slope (exempt acreage sale)
- Mid	Cook Inlet south of Kenai River (exempt acreage sale)
- Late	Upper Cook Inlet onshore and offshore including the Susitna Valley
1981 - Early	Lower Cook Inlet offshore and onshore (coordinated with planned federal sale)
- Mid	Prudhoe Bay uplands
- Late	Norton Basin offshore and onshore (coordinated with planned federal sale)
1982 - Early	Second Beaufort Sea sale (submerged lands)
- Mid	Middle Tanana Basin and Copper River Basin
- Late	Southwest Bristol Bay uplands

1/ Exempt acreage is acreage that can be leased by the commissioner under certain conditions, even though it did not appear on the five-year schedule.

1983 - Early		Upper Cook Inlet onshore and offshore including Susitna Valley (possible drainage sales)
- Mid		Chukchi Sea onshore and offshore (coordinated with planned federal sale)
- Mid		Norton Basin
- Late		Minchumina Basin

LeResche described the governor's new Agency Advisory Committee on Leasing (AACL), which will advise him on the economic, social and environmental impacts of specific proposed lease sales. The committee, to be chaired jointly by the Commissioner of Natural Resources and the Director of Policy Development and Planning, also will include the commissioners of Revenue, Fish and Game, Community and Regional Affairs, Transportation and Public Facilities, Environmental Conservation, Labor, the Attorney General, and an ex officio member from the community or borough where the lease sale is planned.

The committee is to submit a report to the governor at least three months before each major lease sale, Hammond said in a January 5 administrative order creating the committee.

Regulations implementing the new leasing law have been developed by the Department of Natural Resources and will soon be reviewed by other state agencies. The regulations are expected to go to public hearings by late March or early April, and the department hopes to adopt final regulations by mid-May.

Provisions of the New Leasing Law

The most major change in the new law was to expand the commissioner's choice of bidding methods. Formerly the law allowed only one system for leasing state petroleum resources (cash bonus/fixed royalty), but under the new law the commissioner has the following options:

-- A cash bonus bid with a fixed royalty share of not less than 12-1/2 per cent.

-- A cash bonus bid with a fixed royalty share of not less than 12-1/2 per cent and a fixed share of the net profits of not less than 30 per cent.

-- A fixed cash bonus with a share of the net profits as the bid variable.

-- A fixed cash bonus, a fixed royalty share of not less than 12-1/2 per cent and a share of the net profits as the bid variable.

-- A fixed cash bonus with the bid variable a royalty share of not less than 12-1/2 per cent. This method can be used only when the commissioner determines there is evidence that the unleased acreage is subject to drainage by offsetting wells.

Another change in the new law includes a provision requiring companies to give the commissioner "access to all noninterpretive data" obtained from state leases, although the information must be held perpetually confidential at the request of the companies. Previously, companies only had to provide technical information obtained from wells, which was held confidential for two years; the new law does not affect this requirement.

The new law allows, but does not require, the commissioner to establish an "exploration incentive credit" system that would allow companies to earn "credits" for drilling exploratory wells. The credits could be applied against royalties, rental payments and severance taxes. The credit system, modeled on a similar program in Alberta, "has proven to be successful as a way of encouraging high levels of exploratory activity, and in Alberta has been largely responsible for the record-breaking levels of drilling activity in recent years, and subsequent high rates of discoveries since it was introduced in 1974," a Sohio spokesman said in testimony last spring.

The commissioner's authority to reduce royalty payments when a field begins later stages of production decline was restrained by the new law with the adoption of stricter criteria.

The maximum size of any one lease was increased from four square miles to nine square miles in the new law, and the rental rate on state oil and gas leases also was increased.

Philosophical Questions Remain

While the new law outlines goals for the state's leasing policy, it does not resolve several major philosophical questions, including:

-- Should the state share with the oil companies the multi-million dollar risk of oil exploration, as it would do if it deferred a large upfront cash bonus and opted instead for a share of the "net profits" after oil is found and production begins? In what situations might this approach be to the long-run, economic benefit of the state? In what situations might it stimulate industry activity?

-- How quickly does the state need or desire the revenue it will gain from selling its resources? Cash bonus bidding would bring in a large, lump sum payment at the time of sale; net profits bidding would stretch out the payment over a period of years in the future, assuming oil is found and produced.

These questions, as well as technical information on the physical characteristics and resource potential of the area, and analysis of the potential economic payoffs expected, will influence the commissioner's decision on which bidding method to use in any particular sale.

Beaufort Bids Considered

Because the Beaufort Sea is considered a "highly prospective" area, and

may be the state's best hope for finding large accumulations of oil and gas, the choice of a bidding method could have long-term economic implications.

Some people believe that a risk-sharing bid, like net profits, should only be used in a low-risk area where resources are proven or expected to exist. Others say a net profits bid should be used to encourage industry exploration in high-risk areas where the resource potential is more speculative.

Tom Cook, director of the Division of Minerals and Energy Management, said he leans toward use of cash bonus bidding for the Beaufort Sea sale. The net profits method "will be a nightmare" and will require a staff of 15 to 20 economists to administer it, Cook told a group of legislators, consultants and staff in Juneau recently.

"My personal preference is that I lean toward something doable, something we can administer and manage," Cook said. "I have a prejudice to simple approaches, but I'm trying to be open minded." Cook also opposes the concept of state risk-sharing on philosophical grounds.

If the state does use cash bonus bidding, Cook said he would suggest that the fixed royalty share be increased from one-eighth to one-sixth or possibly one-fifth. "This is the only state in the union that's still leasing one-eighth (fixed royalty). Most other states and the federal government have gone to a higher fixed royalty," he said.

Ed Phillips, a petroleum economist with the division who has been analyzing the various bidding alternatives, said it is his personal opinion that "there are many areas in the Beaufort Sea where net profits bidding would be good."

"This is a complex problem, and there are three big uncertainties," Phillips said. "You don't know if there's oil there; you don't know the cost of getting it out; and you don't know what price you'll get for it if you do get it out. Different bidding systems will yield different amounts of income to the state." Phillips said he is setting up a computer model that compares the expected income to the state under different bidding methods and under different assumptions about oil potential, costs and prices. The division is cooperating with the federal Bureau of Land Management in making the same analysis on a tract-by-tract basis.

The oil companies are generally negative about the state assuming a portion of the exploration risk and prefer the traditional cash bonus bid. As Exxon stated in testimony to the House Resources Committee last March, "Sharing in net profits would signal the state's entry into the production phase of the oil business. It might be politically and economically difficult for the state not to be deeply involved in decisions about day-to-day operations and thereby become an operating partner."

AGO 532585

Others, however, argue that a greater assumption of risk by the state would maximize state revenues, reduce the adversarial nature of the state-industry relationship, give the state greater control in the pace of development, and lessen the need for continual tax increases.

A study currently being conducted by White Weld/Merrill Lynch for the Joint Committee on Gas Pipeline Financing will address the benefits and drawbacks of "alternative institutional frameworks under which oil and gas resource development could take place in Alaska."

A bidding method for leasing the state's offshore Beaufort Sea lands has not yet been determined and probably won't be until late spring or early summer. Cook will make a recommendation to Commissioner LeResche, who will make the final decision on bidding terms for the sale. Cook said that although the law does not require it, there will be an opportunity for public comment before proposed bidding terms are finally adopted.

The Federal Perspective

Although the "Memorandum of Understanding" (MOU) signed last spring by Governor Hammond and Interior Secretary Andrus anticipated that joint terms, conditions and procedures would be applied to all Beaufort Sea lands in the sale area, whether they are state, federal or disputed, it has been difficult for the state and federal agencies to agree on a number of points.

Cook said that state and federal managers have now reached "general agreement" on a management structure and on a number of areas where joint regulations and procedures are feasible, including how disputed lands (where both the state and federal government claim title) will be managed while ownership is settled, the basis for unitization (can units include both state and federal tracts?), and mitigating measures to protect the environment. The state and federal government also have agreed to conduct a joint Environmental Impact Statement.

On other points, however, it now appears the state and federal government will proceed in separate directions. Major areas where joint procedures apparently are not feasible, Cook said, include bidding methods and the imposition of restrictions on joint bidding by the oil companies.

The federal government is leaning toward use of sliding scale royalty (not an option under state law) and net profits as bidding methods, Cook said. Even if the state and federal government were both to select the net profits method, Cook said, he would not agree to use the "convoluted" federal definition of net profits.

With respect to joint bidding by major oil companies, state law allows it and federal law does not, although the Interior Secretary can waive the joint bidding ban if he determines that exploration and development will have an extremely high cost and will not occur unless an exemption is granted. Both the Antitrust Division of the Justice Department and the Federal Trade Commission have urged Interior not to grant Chevron's request to lift the restriction for the Beaufort sale. Cook said that

although he does not yet have a formal legal opinion, "it may be that the state doesn't have the power to restrict joint bidding," since a provision giving the commissioner authority to do so was dropped from early versions of the leasing bill and was not included in the version that finally became law.

Some believe it will be difficult for the state and federal government to pull off the sale on schedule this December, considering the administrative problems, legal challenges and general opposition from Natives who live near the proposed sale area, and uncertainty about environmental effects, particularly on the bowhead whale.

Exxon executive Monte Taylor recently visited Juneau to "impress on the governor the importance of keeping it on schedule," or at least letting industry know as soon as possible if it will be delayed.

"We've got 15 to 20 people working on the Beaufort Sea...we're spending a lot of money getting ready," Taylor said in an interview with the public television show, Capital 79.

Although the villages of Nuiqsut, Kaktovik and Barrow have been denied injunctions attempting to halt preparatory drilling near the sale area in both federal and state courts, their cases against the state, the U.S. Army Corps of Engineers and Exxon are still pending. Cook said he thinks it is "very likely" that Exxon will have completed its drilling from a man-made gravel island in the mouth of the Sagavanirktok River before the case comes to trial.

Sohio recently got permits from the state and federal governments to construct a similar gravel island in shallow water on the northern edge of Prudhoe Bay. Alaska Legal Services, which is representing the Natives in the suits against Exxon and the governments, has threatened to challenge Sohio's drilling in court as well.

INTERIOR ISSUES DECISION ON PLO 82

The Department of Interior has issued a legal opinion that affirms the state's ownership of Prudhoe Bay but claims federal ownership of other large sections of offshore Arctic Alaska.

The December 12 opinion by Interior Solicitor Leo Krulitz, which has been approved by Secretary Cecil Andrus, claims federal ownership of offshore lands bordering on the Arctic National Wildlife Range and the National Petroleum Reserve in Alaska (NPRA). This means, in effect, that the state would own only the narrow, three-mile strip of offshore Beaufort Sea lands between the two federal withdrawals.

In addition, the Interior opinion claims federal ownership of inland submerged lands (navigable lakes and rivers) within the large land area withdrawn by the federal government in Public Land Order (PLO) 82.

Both the offshore lands and the inland submerged lands now being claimed by Interior as federal property formerly were thought to have passed into state ownership at statehood.

Assistant Attorney General Tom Koester said the opinion is "unacceptable to the state with respect to ownership of the inland water bodies and ownership of the offshore submerged lands not expressly included in the withdrawals for NPRA and the wildlife range." Koester said the state is now evaluating its legal options for seeking a reversal in those two areas. However, he said, "we are pleased that the solicitor has confirmed the state's ownership of the lands under Prudhoe Bay."

PLO 82 withdrew more than 48 million acres of Alaska lands north of the Brooks Range crest for military purposes in 1943, but the order was revoked in 1960.

"The issue involving coastal submerged lands has been raised in connection with a proposed sale of oil and gas resources in submerged lands in the Beaufort Sea off northern Alaska, which would be a joint sale conducted by the (Interior) Department and the State. The need to clarify the status of ownership in connection with this proposed joint sale has been the catalyst which has prompted this opinion," the solicitor's opinion said.

Current ownership of the lands, Krulitz said, is based on: (1) whether PLO 82 withdrew either offshore submerged lands or inland submerged lands in northern Alaska; (2) if so, whether this withdrawal effectively prevented transfer of federal ownership to the State of Alaska upon statehood; and (3) if so, whether revocation of PLO 82 in 1960 vested ownership of lands in the State.

Krulitz concluded that the coastal submerged lands were not withdrawn by PLO 82 and consequently passed to the state at statehood. However, he said, the offshore lands abutting NPRA were reserved by the federal government in Executive Order 3797-A of February 23, 1923, and did not pass to the state at statehood. The offshore lands abutting the Arctic National Wildlife Range were reserved to the federal government by the Bureau of Sport Fisheries and Wildlife application for a withdrawal dated January 14, 1958, and do not belong to the state, he said.

"I have also determined that, in contrast to the coastal submerged lands, the inland submerged lands were withdrawn by PLO 82, did not pass to the State of Alaska at statehood, and remain in federal ownership despite the revocation of PLO 82 in 1960, except where the State of Alaska has selected the submerged lands in question and the Federal Government has approved these selections," Krulitz said.

Koester said it is impossible to determine how much acreage is affected by Interior's opinion on the lakes and rivers since there is some dispute about how navigability is defined. The state favors the view "that if you can land a float plane on it, it's navigable," Koester said. However, the federal government, which has clear title to the non-navigable water bodies, wants navigability based on proof of historical use in trade and commerce.

AGO 532588

ALASKA URGES INTERIOR TO POSTPONE PROPOSED OCS SALES

About a third of 11 federal offshore lease sales proposed in Alaska for 1980-85 should be postponed indefinitely, Governor Jay Hammond recommended recently to Interior Secretary Cecil Andrus.

Interior is in the process of drawing up a new five-year leasing schedule for all Outer Continental Shelf (OCS) areas in the United States. Of 22 areas proposed for sale in the next five years, half are in Alaska. Interior's "draft proposed program," which will name specific dates and areas for leasing, will be submitted to Hammond and other governors by March 2.

Under 1978 amendments to the federal OCS Lands Act, Interior is required to solicit comments on the proposed five-year plan from states, local governments and interested members of the public.

In a December 12 letter to Andrus, Hammond said proven technology for development in the 1980-85 period currently exists in only three of the 11 proposed sale areas -- the nearshore Beaufort Sea, the Gulf of Alaska (Yakutat tracts) and the Lower Cook Inlet/Shelikof Strait.

Proposed sales in four other areas -- Navarin Basin, Norton Basin, Hope Basin and the Kodiak Shelf -- "need to be delayed until proven, safe technology is developed through experience gained in the nearshore Beaufort Sea," Hammond said. The governor recommended "sequential nearshore to offshore progression of development" for these areas. "The nearshore areas of Norton and Navarin Basins may be appropriate areas for leasing by 1983-85, assuming advanced exploratory and development drilling techniques and mitigating measures are developed in the nearshore Beaufort Sea by the early 1980s, and if district coastal management plans are satisfactorily completed," he said.

Sales in five other areas -- Chukchi Sea, Southern Aleutian Shelf, St. George Basin, Bristol Basin and the Beaufort Sea ice shear and offshore pack ice zones -- "need to be postponed indefinitely pending resolution of major renewable resource conflicts, availability of a comprehensive coastal environmental data base for development of strengthened regulatory mechanisms, decisions on marine sanctuary designation or other protective classification, evolution of Arctic technological capability and completion of coastal management plans," the governor said.

Interior's current proposal would mean about two federal OCS lease sales a year for the next five years, Hammond said, and the economic and environmental effects of the separate sales will interact.

"The total impacts associated with these separate activities would likely be cumulative and the total impacts would differ significantly from what one would expect from 11 separate sales," he said. The governor questioned whether the current Environmental Impact Statement process, which will examine each sale separately, would be adequate to assess the cumulative effect of 11 sales in five years.

ALASKA URGES INTERIOR TO POSTPONE PROPOSED OCS SALES

About a third of 11 federal offshore lease sales proposed in Alaska for 1980-85 should be postponed indefinitely, Governor Jay Hammond recommended recently to Interior Secretary Cecil Andrus.

Interior is in the process of drawing up a new five-year leasing schedule for all Outer Continental Shelf (OCS) areas in the United States. Of 22 areas proposed for sale in the next five years, half are in Alaska. Interior's "draft proposed program," which will name specific dates and areas for leasing, will be submitted to Hammond and other governors by March 2.

Under 1978 amendments to the federal OCS Lands Act, Interior is required to solicit comments on the proposed five-year plan from states, local governments and interested members of the public.

In a December 12 letter to Andrus, Hammond said proven technology for development in the 1980-85 period currently exists in only three of the 11 proposed sale areas -- the nearshore Beaufort Sea, the Gulf of Alaska (Yakutat tracts) and the Lower Cook Inlet/Shelikof Strait.

Proposed sales in four other areas -- Navarin Basin, Norton Basin, Hope Basin and the Kodiak Shelf -- "need to be delayed until proven, safe technology is developed through experience gained in the nearshore Beaufort Sea," Hammond said. The governor recommended "sequential nearshore to offshore progression of development" for these areas. "The nearshore areas of Norton and Navarin Basins may be appropriate areas for leasing by 1983-85, assuming advanced exploratory and development drilling techniques and mitigating measures are developed in the nearshore Beaufort Sea by the early 1980s, and if district coastal management plans are satisfactorily completed," he said.

Sales in five other areas -- Chukchi Sea, Southern Aleutian Shelf, St. George Basin, Bristol Basin and the Beaufort Sea ice shear and offshore pack ice zones -- "need to be postponed indefinitely pending resolution of major renewable resource conflicts, availability of a comprehensive coastal environmental data base for development of strengthened regulatory mechanisms, decisions on marine sanctuary designation or other protective classification, evolution of Arctic technological capability and completion of coastal management plans," the governor said.

Interior's current proposal would mean about two federal OCS lease sales a year for the next five years, Hammond said, and the economic and environmental effects of the separate sales will interact.

"The total impacts associated with these separate activities would likely be cumulative and the total impacts would differ significantly from what one would expect from 11 separate sales," he said. The governor questioned whether the current Environmental Impact Statement process, which will examine each sale separately, would be adequate to assess the cumulative effect of 11 sales in five years.

Hammond reiterated the state's "grave concern" that environmental assessment research programs be adequately funded, and urged Interior to seek a supplemental appropriation from Congress for the current fiscal year.

Hammond also said he considers resolution of the West Coast surplus "inseparable from federal planning for major oil and gas leasing on Alaska's OCS...

"Clearly the United States government must mesh its accelerated leasing plans with the realities of existing refinery capacity, the existing transportation systems, and the institutional mechanisms which affect the incentives for industry to adjust these facilities and systems," he said.

Until some solution is implemented to alleviate the surplus -- such as retrofitting existing West Coast refineries, constructing one or more of the west-to-east crude oil pipelines, or exporting North Slope oil to Japan in return for other foreign oil delivered to the U.S. Gulf and East Coasts -- "anything that increases the crude oil supply on the West Coast can only serve to exacerbate this problem," the governor said.

INTERIOR CALLS FOR NOMINATIONS IN LOWER COOK INLET

Interior's Bureau of Land Management has invited the oil industry to nominate tracts for possible inclusion in the planned OCS sale in Lower Cook Inlet, now tentatively scheduled for March, 1981.

BLM also asked for comments on geological, environmental, biological, archaeological and socio-economic problems that might affect leasing and development of specific blocks. The call for nominations and comments, due by February 28, is a preliminary step to selection of tracts for further environmental analysis and study.

The area covered in the present call for nominations includes all of Lower Cook Inlet south of Kalgin Island (except tracts leased in the October, 1977, sale), and the Shelikof Strait as far south as Cape Ikolik on Kodiak Island.

Gas Pipeline

SCHLESINGER SUGGESTS FEDERAL LOAN GUARANTEE FOR ALASKA HIGHWAY PIPELINE

Energy Secretary James Schlesinger says a $2 billion to $3 billion federal loan guarantee may be needed to build the Alaska Highway gas pipeline if private financing can't be arranged.

Schlesinger made the remark in testimony before the Joint Economic Committee of Congress in response to questioning by Senator William Proxmire of Wisconsin, the Wall Street Journal reported January 24.

Previously, the administration had maintained that the Alaska pipeline could be privately financed, as required by federal law.

In a mid-January address in New York, Schlesinger labeled the project a "high priority" of the administration and urged the financial community to remain sympathetic until regulatory decisions are resolved. Even in the unlikely event of a 90 per cent cost overrun, Schlesinger said, the Alaska project will be more beneficial to the nation in the long run than other alternative gas supplies whose prices are tied to the world price of oil.

Schlesinger told the Senate Energy Committee that although the long delay over the natural gas pricing bill had caused the Alaska project to lose momentum, the Federal Energy Regulatory Commission (FERC) should have "pulled the regulations in place" within the next 60 days.

Schlesinger's prediction of quick FERC action is considered unreasonably optimistic by most observers. FERC's latest order on one aspect of the Incentive Rate of Return (IROR) outlined a procedure for resolving more than a dozen complex matters, several of which will require separate rulemaking procedures. Considering the length of time it has taken FERC to establish even the basic structure of the IROR (the first notice of rulemaking was issued last May), it is almost certain that regulatory deliberations will drag on for many, many months, or perhaps a year.

Despite Schlesinger's renewed assurances of support, the Alaska Highway gas pipeline project continues to face enormous obstacles and problems.

President Carter still has failed to nominate a Federal Inspector and submit his proposal for reorganizing the federal bureaucracy, long-delayed actions that had been expected by the time Congress convened January 15. The reorganization will affect the departments of Agriculture, Energy, Interior, Labor, Transportation, Treasury, the Environmental Protection Agency, the Army Corps of Engineers and the Federal Communications Commission, and will transfer their enforcement authorities over construction of the Alaska pipeline to the Office of the Federal Inspector.

Alaskan Northwest, sponsor of the Alaska segment of the pipeline, recently told federal officials in Washington it now expects to complete the project in the "winter season" of 1984-85, a year later than the previous estimate.

Although Northwest's ability to secure private financing for the project remains in doubt, the project sponsors appear to have momentum in their favor on the critical issue of who should build and pay for the North Slope conditioning facilities, estimated to cost about $2 billion. FERC has under consideration a proposed rulemaking that would place responsibility for these facilities on the producers, but it has not been formally adopted. If this view ultimately prevails, Northwest will be relieved of one major task. The producers do not like this proposal, however, and it could weaken their interest in producing and selling the gas.

Congress is expected to begin reexamining the necessity for an Alaska gas pipeline in the context of hearings this spring on the overall gas supply situation, with particular attention to Canada and Mexico. While some members of Congress still strongly support the Alaska gas line for

national security reasons, some other pro-consumer congressmen, like Senator Edward Kennedy, are questioning why consumers should pay for expensive Arctic gas when cheaper, closer supplies are, or may be, available. At Schlesinger's appearance before the Joint Economic Committee of Congress, Senator Kennedy accused the Energy Secretary of spurning Mexican gas and of tailoring federal policies to raise domestic gas prices enough to justify construction of the Alaska gas line, the Wall Street Journal reported.

Given all the uncertainties and lack of progress at the federal level, it appears increasingly unlikely that either the state administration or the legislature's Joint Gas Pipeline Financing Committee will recommend that state funds be committed to the project during the current legislative session. Governor Hammond, in his State of the State address, said, "It is totally premature for the state to make final decisions regarding what, if any, financial investment we may wish to make."

Northwest, however, reportedly intends to make a strong push for an early state commitment of $500 million in equity, as well as an attempt to convince the state to sell its royalty gas for export through the pipeline.

Some of the issues affecting progress on the project are discussed in more detail below.

Conditioning Costs

A proposal that would require gas producers to pay for the costs of gas conditioning out of the $1.63 per million Btu maximum wellhead ceiling price has been on FERC's agenda since early December, but has not yet been adopted as a formal "proposed rulemaking." If the proposal is adopted, there likely will be an extended period for comment by the various parties before the matter is finally settled by FERC. FERC's decision could be appealed to the courts.

If the conditioning costs are included within the ceiling price, the value of the gas to the producers probably would drop below $1. The producers also object to this proposal because it would require that they, rather than the pipeline sponsors, bear the front-end financial burden of raising about $2 billion to build the facilities.

The proposal under consideration by FERC says this arrangement is "necessary to insure the marketability of the gas."

It is presently unclear what effect this proposal, if adopted, would have on state royalty gas, whether the wellhead value used to calculate royalty and severance tax payments would be the ceiling price, or the ceiling price minus the estimated 75¢ conditioning cost. Natural Resources Deputy Commissioner Fred Boness said the matter might have to be settled in court.

Field Economics

In order for the pipeline to go forward, gas sales contracts will have

to be negotiated between the North Slope producers and the pipeline companies. There must be buyers and sellers who agree on an acceptable price for the gas.

It is not known, except perhaps by the producers themselves, at what price it will be economical to produce and sell the gas, considering the amount of investment required for conditioning facilities, pressure maintenance, and the cost of reinjecting the gas if it is not produced.

The Department of Natural Resources and the Legislative Affairs Agency's Research Division are now reviewing proposals for an analysis on the economics of producing gas from the Prudhoe Bay field. This economic analysis will "model" the costs of producing and not producing the gas, as well as predict returns expected under a range of conditions, based on engineering profiles of the reservoir.

Pipeline Pressure

Northwest wants to build a 48-inch diameter pipeline with an operating pressure of 1,260 psi (pounds per square inch), while Atlantic Richfield and the state favor a higher pressure, 1,440 psi system.

Northwest currently is preparing a report on the issue for presentation to FERC, which will make the final decision. Members of the pipeline consortium met with state officials in Juneau recently in an attempt to get the state to change its position.

The higher pressure, 1,440 system would be able to move gas more cheaply at throughput levels above 3.4 billion cubic feet (bcf) a day. Below that throughput level, the 1,260 system can move gas more cheaply per unit, according to figures supplied by Northwest.

Since gas production almost certainly will be limited by reservoir management considerations, throughput from the Prudhoe Bay field probably will not exceed 2 bcf a day.

Therefore, Northwest reasons, the lower pressure system will be more efficient at the throughput level expected. Northwest says the 1,260 system could be expanded to accommodate a throughput of 3.2 bcf a day with additional compressors, and it maintains that this is adequate extra capacity.

The state and others argue, however, that future discoveries likely will increase the amount of gas available for production, and that it would be much cheaper to put in extra capacity during initial construction rather than adding it later. (For a more full explanation of the state's position, see "Energy Background Report #3," December 8, 1978, Page 6.)

In addition to the advantage of improved efficiency at the lower throughput level, Northwest Vice President Darrell MacKay gave a number of other reasons for selecting the 1,260 system.

AGO 532593

Northwest maintained that any change in its plans to build the lower pressure system will delay completion of the project at least a year, jeopardize the project's economic viability, frighten off prospective financiers, and render useless many months of predesign and engineering work.

Lenders are not willing to take the technological risks associated with the higher pressure system, MacKay said, noting that no large-diameter gas transmission pipeline has ever been built with a design pressure greater than 1,100 psi.

With respect to the amount of liquids that can be carried at the different pressures, Northwest presented figures showing that the higher pressure, 1,440 system can carry a slightly greater (8,000 barrels a day) amount of butane and heavier liquids. Northwest emphasized, however, that both systems could carry the same amount of ethane and propane.

"We believe and agree with Bonner and Moore that ethane is the best material for petrochemical feedstock," MacKay said. Since the 1,260 line could carry almost double the maximum amount of ethane needed for a world-scale petrochemical plant, MacKay said, "we don't think we've inhibited your flexibility" in developing a petrochemical industry.

The figures presented by Northwest are shown below, and they reflect the amount of liquids that could be carried in the gas stream at the 1,260 and 1,440 pressures.

PRUDHOE BAY FIELD
NATURAL GAS LIQUIDS
GAS PRODUCTION RATE OF 2 BILLION CUBIC FEET
PER DAY

	Natural Gas Liquids (thousand barrels/day) Design Pressure (psig)		
	1260	1440	Increase
Liquids Acceptable in Gas Stream			
Ethane	98	98	-
Propane	53	53	-
Butane	9	15	6
Pentanes and heavier	2	4	2
	162	170	8
Liquids Not Transportable in Gas Stream			
Ethane	0	0	-
Propane	0	0	-
Butane	22	16	(6)
Pentanes and heavier	22	20	(2)
	44	36	(8)

These figures, however, do not represent the actual amount of liquids that will be carried if the producers implement their current plans as set out in the conditioning plant study by the Ralph M. Parsons Co. The producers, at this time, plan to burn a large portion of the liquids as fuel on the North Slope.

Figures developed by Earth Resources Company of Alaska (ERCA) and Northwest forecasting the amount of liquids that actually will be carried at the 1,260 pressure are shown below.

NATURAL GAS LIQUIDS
(Barrels per day)

	ERCA	Northwest
Total Liquids Produced	182,599	226,000
Liquids to be carried in pipeline	75,470	105,000
Ethane	46,500	56,000
Propane	17,970	22,000
Butane	9,000	26,000
Pentanes and heavier	2,000	1,000

Earth Resources of Alaska, which is the parent company of North Pole Refining in Fairbanks, made a presentation at a recent royalty board meeting urging the state to reject the lower pressure, 1,260 system and the current plan to build the conditioning facilities on the North Slope.

ERCA suggested that a high-pressure 1,680 system be constructed from the North Slope to Fairbanks to deliver the entire, unconditioned gas stream, including almost all the liquids. A gas conditioning and separation facility to remove the liquids should be built at Fairbanks, ERCA said. The treatment and separation facility should be financed and operated by the state under an AGSOC concept backed by the permanent fund, they suggested, and the portion of the natural gas pipeline between Prudhoe and Fairbanks also could be partially financed through the AGSOC.

"The proposal submitted by the Ralph M. Parsons Company, and being considered by FERC, considers the burning of a good portion of the gas liquids as fuel at Prudhoe Bay," ERCA said in a "white paper" presented to the royalty board. "Permitting such burning of gas liquids minimizes any opportunity to develop a viable gas liquids separation plant in the Interior and detracts from the viability of developing a petrochemical plant in Alaska."

Incentive Rate of Return

FERC's latest order (No. 17-A of 1/17/79) settled the issue of whether an Allowance for Funds Used During Construction (AFUDC) will be included in the Cost Performance Ratio of the IROR mechanism. AFUDC will be

included, despite assertions by Northwest that the arrangement will hinder attempts to arrange private financing.

FERC made some adjustments in its earlier order (No. 17 of 12/1/78) and agreed with Northwest that the pipeline sponsors should not be penalized for delays beyond their control. However, FERC kept the basic structure of its December order intact.

The Incentive Rate of Return mechanism, mandated in the President's Decision selecting the Alaska Highway pipeline route, is supposed to prevent large cost overruns like those experienced during construction of the Trans-Alaska oil pipeline. The IROR will allow the pipeline companies and other equity investors to earn a high rate of return if the project is constructed within or under budget, but it will reduce earnings if the project ultimately costs more than projections.

Despite Order 17-A, many issues with respect to implementing the IROR remain unresolved.

Marketability

Whether Lower 48 consumers will be willing to buy high-cost Alaska gas continues to be an issue of speculation, in spite of the "rolled-in" pricing provisions in the new Natural Gas Policy Act.

Secretary Schlesinger recently told the Senate Energy Committee that the present combined wellhead and delivery price for Alaska gas is about $4.85 per million Btu's (Foster Report of 1/18/79). Schlesinger estimated that this would decrease during the life of the pipeline to $3.50 by 1995 and $3.12 by the year 2000. He said he would oppose any attempt to equalize the cost of pipeline transportation over the life of the line. While this would reduce the burden on today's consumers, it would increase risks and result in higher capital costs, he said.

A recent report by the Congressional Research Service, however, indicated that delivered Alaska gas is likely to cost $5.58 to $6.30 per million Btus in 1985. 1/

Consultants Arlon Tussing and Connie Barlow said in a January report to the legislature: "Gas delivered through the Alaska Highway system would cost Lower 48 consumers more than twice today's prices for fuel oil, and although oil prices are almost certain to keep rising, there is no assurance that Alaska natural gas will be saleable in competition with other fuels over the project's entire economic life." (See next item.)

Actions of Northwest's Corporate Rivals

Midwestern Gas Transmission Co., one of the parties that recently lost the first round of a lawsuit seeking to prevent Northwest from importing

---

1/ Caution must be exercised in comparing projected costs unless the reference year and other assumptions are specified. The Foster Report quoting Schlesinger's remarks did not name the reference year.

Canadian gas through the pipeline's pre-built Eastern Leg, has now challenged applications of the companies building the pipeline's Western Leg.

Midwestern and others recently asked FERC to hold formal evidentiary hearings on the Western Leg applications, which were filed in November by Northwest Alaskan Pipeline Co., Northwest Pipeline Corp., El Paso Natural Gas Co., Pacific Interstate and Pacific Gas Transmission Co.

Midwestern's arguments center around the legal problems posed by a change in routing for the Western Leg from that accepted in the President's Decision.

This question may prove to be an important test of how closely the applicants will be held to routing and other conditions set forth in the President's Decision approving the Alaska Highway route and its southern sections.

FEDERAL LEADERSHIP NEEDED TO BREAK GAS PIPELINE IMPASSE

The Alaska Highway gas pipeline project will continue to flounder until its sponsors and the federal government face up to the realities that private financing is not possible and an explicit allocation of risks is necessary, legislative consultants say.

Arlon Tussing and Connie Barlow said in a recent report to the legislature that the problems and conflicts now confronting the pipeline project have grown out of three troubling characteristics: (1) its marginal economics, (2) the accompanying uncertainties and risks, and (3) the need for an explicit allocation of those risks.

"What is holding up the project is not the scheduling and resolution of a host of individual events -- incentive rates of return (IROR), conditioning costs, gas sales contracts, etc. -- but a resolution of the basic question of who will bear what risks, and in return for what benefits?"

The risks faced by lenders include the possibilities that the cost of Alaska gas might exceed its market value, that TAPS-like cost overruns might push the project's price tag far above current estimates, that engineering or regulatory problems might prevent completion of the project after actual construction had begun, or that gas production might be interrupted for an extended period.

"Traditionally, large transportation projects have been 'conventionally' financed, that is, in a way that the sponsors are assumed to bear all risks," the report said.

"'Project financing' as proposed for the Alaska gasline, however, is a relatively new technique in which the sponsors risk only their invested equity capital. The sponsors will not be liable for debt service; altogether, their net worth is not large enough to meet this responsibility even if they were willing to do so. Lenders, on the other hand, cannot

afford to take any risks when the stakes are so great. They must therefore be assured that some other creditworthy party will assume responsibility for scheduled payments of debt and interest in the event of project non-completion or a shortfall in revenues during some 25 years of operations. The transfer of these risks onto such parties must, therefore, be tight, complete, and explicit," the report said.

"In our view," the authors said, "among all the beneficiaries, only the federal government is large enough, and only the federal government can capture enough of the non-marketable benefits of the project, to be able and motivated to provide the essential financial guarantees."

The report traces some of the history surrounding federal selection and approval of the Alaska Highway project, and points out that the Carter administration and the project's sponsors currently face an almost impossible political dilemma. The Alcan sponsors (now Alaskan Northwest) told Carter the pipeline could be privately financed; the President took those optimistic claims at face value and assured Congress that federal financing assistance would not be necessary.

"Thus the project sponsors and the administration hooked Congress -- and themselves. Their failure to address the financing question openly and realistically from the beginning has sowed seeds of suspicion that could well prove fatal to the project, or at least to its present sponsors, when and if they finally decide to ask for federal help," the report said. "Moreover, the optimism of Northwest and the President that loan guarantees or unconventional tariff designs would not be needed has seemingly been turned into a Congressional dogma that such assistance absolutely shall not be given."

Given these factors, Tussing and Barlow conclude, "on the surface it looks as if the state can avoid for a least another year confronting the difficult policy questions: (1) does the state want to contribute risk capital to assist the project? and (2) what should be done about the royalty gas? After all, until the fundamental risks are explicitly apportioned, it is impossible to make prudent judgments, either on the soundness of financial involvement or on how critical state financing or royalty decisions are to the project's success."

The authors outlined three possible "alternative postures" that the state might take with regard to the project in the coming year:

> (1) Defensive -- This approach, which corresponds most closely to the postures taken by both legislative and executive branches in the past year, is grounded on a belief that although it is best for the state to avoid any direct responsibility for progress of the pipeline, it is nonetheless vital for the state to take some action to protect its interests and to stake out bargaining positions. "The driving force to take some action can be either concern that the state might be stuck with the blame of project failure, or recognition of a need to at least keep up with the other parties in asserting its interests and reacting to their proposals."

2. Offensive -- The state could be the first to "lay its cards on the table," hoping that others would then do the same. The state could make a commitment to follow through on a particular action, like equity financing, if certain enumerated conditions were to occur first. While this might be an effective way to jar things off dead center, it might also have a debilitating effect if the state's demands proved to be unrealistic and unachievable.

3. Strategic -- With this posture the state would serve as a behind-the-scenes catalyst in an attempt to get the other parties, particularly the federal government, to turn away from the present adversarial, piecemeal approach. The state would be trying to get each party to understand the financial and political limitations restraining every other party.

John G. McMillian, chairman and chief executive officer of Northwest Alaskan, blasted the Tussing-Barlow report at a recent Fairbanks news conference, according to the All-Alaska Weekly. "We can privately finance this project," he was quoted as saying.

The report, "The Alaska Highway Gas Pipeline: A Look at the Current Impasse," was prepared under a contract between the University of Alaska's Institute of Social and Economic Research and the Legislative Affairs Agency. Copies are available in the agency's Research Division office, or from the Anchorage and Fairbanks public information offices.

Royalty Oil and Gas Development

DEVELOPING AN IN-STATE PETROCHEMICAL INDUSTRY REQUIRES STATE ACTION

Development of an in-state petrochemical industry with Prudhoe Bay gas liquids appears most feasible if the Alaska Highway gas pipeline is scrapped or delayed indefinitely, but the industry is unlikely to develop in any circumstance unless the state exerts stronger leadership, consultants say.

Bonner & Moore Associates, Inc., of Houston, in a January 10 report to the Royalty Oil and Gas Development Advisory Board, recommended the state spend about $300,000 to design and develop a financing plan for a gas liquids pipeline from Prudhoe Bay to tidewater. This pipeline would be "the key...component of a system to use gas liquids in-state," the report said.

The royalty board, meeting in Juneau February 1, voted unanimously to request that the governor seek a supplemental appropriation from the legislature for work on the liquids pipeline as suggested by Bonner & Moore.

The report said the state should consider the possibility of state financing for the project, which could reduce the cost of getting the gas liquids to tidewater by 15 to 20 per cent.

AGO 532599

Actively promoting a liquids pipeline "is the only approach we can see that will enable the state to influence events favorably toward petrochemical industry development," the report said.

Consultant Joe Moore said his strategy and recommendations are "predicated on the notion that the gas line is not going to be built, at least not in the near future." If the pipeline is built, it is likely that the value of the gas liquids will be greater if they remain in the gas stream and are exported to the Lower 48.

Private industry is unlikely to pursue development of petrochemical manufacturing in Alaska for several reasons, the report said.

"Regulatory delays, high transportation costs, and a generally negative perception of the business climate in Alaska have resulted in an impasse over the matter of gas production and sale. The prospects of catalyzing industrial leadership in the use of gas liquids in-state are poor for these reasons," the consultants said. "A thoughtful consideration of alternatives has led Bonner & Moore to a reluctant but firm conclusion that only a commitment by the state to lead these activities can significantly enhance the prospects of in-state petrochemical development."

Federal regulations on the pricing of Prudhoe Bay gas will affect the economic viability of the Alaska Highway gas pipeline as well as the feasibility of in-state petrochemical manufacturing. It is uncertain at this time whether the Federal Energy Regulatory Commission ultimately will allow the producers to recover their conditioning costs in addition to the wellhead ceiling price of $1.63 per million Btus, or whether those costs will be included within the price ceiling.

Another big uncertainty is how much Lower 48 gas purchasers are willing to pay for Alaska gas; they may not be willing to pay the ceiling price (plus transportation) regardless of how the conditioning issue is settled.

"At the present time," Bonner & Moore said, "the prospects of selling Prudhoe Bay gas at regulated ceiling prices appear to be dimming. While this is an unwelcome development for Alaska, in that it reduces the royalty value of North Slope gas production, it enhances the prospect that the alternate value of these materials as petrochemical feedstocks will become their most economic disposition and therefore provide the greatest benefit to the state."

Bonner & Moore estimated that the cost of recovering the ethane and heavier liquids at the North Slope and transporting them by pipeline to the Kenai Peninsula would amount to about $1.08 per million Btus. The value of the feedstock to the manufacturer (or the amount he is willing to pay for it), considering petrochemical prices and manufacturing costs, is about $2.10 per million Btus. Therefore, the liquids would have a value of about $1.02 per million Btus at the North Slope. This means a manufacturer may be willing to pay the producers or the state up

to $1.02 per million Btus for the liquids at the wellhead. 1/

The consultants outlined three possible outcomes for pricing Prudhoe Bay gas.

Under one scenario, Prudhoe Bay gas is allowed a regulated price of $1.63 per million Btus, plus the cost of gas conditioning, and the gas is sold successfully at that price. In this situation, the prospect for in-state use of the liquids for petrochemicals is zero, the consultants said.

Under the second scenario, Prudhoe Bay gas is allowed a regulated price of $1.63 per million Btus, but no added allowance is made for an estimated 75¢ gas conditioning cost. In this situation, in-state petrochemical manufacturing is "feasible," Bonner & Moore said, since the liquids' "pipeline value" (the amount the producers can get for selling them for export through the pipeline) is about 88¢.

In the third possibility, Prudhoe Bay gas only can be sold at a market clearing price in competition with other gas supplies available to purchasers in the Lower 48. If this were to occur, prospects for petrochemicals are "good," but it is unlikely that the Alaska gas line would be built. Bonner & Moore said that in this situation "the producers could well make a concerted effort to recover and sell gas liquids from Prudhoe Bay, reinjecting only a lean gas stream back into the reservoirs."

"The determination of which scenario will prevail must first await the final regulations on gas pricing to be adopted by FERC. Even these regulations will not completely define the gas pipeline's future because the entire gas project has not met the test of market acceptance. In the view of Bonner & Moore, the gas pipeline project, or at least the Alaskan portion, is not economically sound. Only substantial government subsidization or favorable regulatory bias toward the project will enable its realization."

Moore did not address in the report whether petrochemicals might be feasible if the Alaska Highway gas pipeline ultimately is built and the liquids are transported through it rather than through a separate liquids pipeline.

One problem, however, is that if all the gas liquids are taken out of the gas stream for petrochemical manufacturing and sale as products, the Btu value of the gas stream would be significantly reduced. Although a world-scale petrochemical facility would need no more than 50,000 barrels

---

1/ These figures assume that construction costs in Alaska are 40 per cent higher than on the U.S. Gulf Coast. If construction costs were 100 per cent higher, the feedstock value (or the amount the manfacturer can afford to pay) would drop 61 per cent.

a day of liquids out of a total of 150,000 to 180,000 barrels a day of liquids that could be produced, the economies of scale for the extraction plant and products pipeline virtually require extraction of the maximum amount of liquids available. Moore said it might be feasible to remove only 50,000 barrels of liquids a day at Fairbanks, "provided you didn't have to pipeline it somewhere else, if it could be converted into some other product like plastic that could be transported by rail."

Northwest Alaskan Vice President Darrell MacKay told a meeting of state officials in Juneau recently that "if 80 per cent of the ethane and heavier liquids were extracted for petrochemical manufacturing or sale, it would have a very significant effect on our system downstream...Twenty to 25 per cent of the Btu value of the gas stream would be gone. It would affect the economic viability of the whole project."

MacKay said Northwest wants "to help the state accomplish its goal for in-state use of the liquids." However, "we think you'll find that it's more profitable to keep the liquids in the gas stream rather than extract them for export and sale as liquids," he said.

Moore said that if the Northwest pipeline is built, and the liquids are removed for petrochemical manufacturing and sale as products, one solution might be to replace the Btus lost from the Prudhoe Bay stream with Cook Inlet gas transported in a new lateral pipeline.

Royalty Gas Sale Uncertain

It now appears less likely the administration will attempt to conclude a sale of the Prudhoe Bay royalty gas and gas liquids during the current legislative session.

Natural Resources Commissioner Robert LeResche said the administration had been giving serious consideration to selling the royalty gas in a "promotional option" contract "because there's been so much pressure from people, particularly in Fairbanks, who are convinced that the only way to get a petrochemical industry is to give someone a commitment to use the gas."

The Royalty Oil and Gas Advisory Board, which must approve royalty sales proposed by the administration, decided at its last meeting to delay consideration of the sale until mid-March. The board asked LeResche to continue talks with prospective purchasers and to continue work on the draft contract.

The royalty board was divided on whether a Prudhoe Bay royalty gas sale should take place this spring. Revenue Commissioner Sterling Gallagher opposed the promotional contract sale because "it will be detrimental to the (Northwest) gas pipeline." Others suggested the state should wait for the outcome of the liquids pipeline study, expected to take about six months, before a decision is made.

Unlike last year when the legislature considered a royalty oil contract, which already had been awarded to ALPETCO after competition among a number of firms, LeResche had planned this year to initially send down only the structure of an unawarded contract. Bidding among prospective purchasers would take place later, if the legislature approved the contract and endorsed the concept of a sale. It is likely the contract would have to be approved by the legislature a second time after being awarded to the high bidder.

The draft contract prepared by the attorney general's office requires that the gas either be "processed or consumed" in Alaska. The buyer would have to "construct and operate, or cause to be constructed and operated, a facility for the in-state processing of the gas sold under this agreement."

The draft contract would sell 80 per cent of the Prudhoe Bay royalty gas for 20 years. The price for the gas would be at least the amount the state would have received by taking the gas in-value (in cash), and potential purchasers probably would bid a variable number of cents above the in-value floor. The administration is considering inclusion of a "franchise fee" either as a bid variable or as a fixed amount. LeResche said the state also would require an assignment fee if the option were sold to someone else.

In a January 19 letter to 17 prospective purchasers, LeResche said he had decided it was "unwise" to pursue the course detailed in the original solicitation circulated by the department last summer to 500 firms. Rather, LeResche said, he is "considering a more flexible approach to promote entrepreneurial pursuit of in-state use of our royalty gas."

Only 23 firms responded to the original solicitation, which tentatively set the sale for late March. The most recent solicitation was sent only to those firms that indicated an interest in using or processing the gas in Alaska.

"I would solicit your review of this draft (contract) and your comments on its principles, as well as any indication of whether your firm would be interested in pursuing something along these lines," LeResche's letter said.

The Fairbanks North Star Borough, one of the leading proponents of a royalty gas sale this year, said in a letter to LeResche it "strongly supports" the concept of a promotional contract.

"The borough would like to commend you for adopting this generalized contractual approach as a means of preventing the stagnation of interest in the state's royalty gas efforts, as well as insuring that federal decisions in Washington, D. C., not take the disposition of the gas out of the state's hands during the interim," Borough Mayor John Carlson said.

Carlson reiterated the borough's interest in assuring the availability

AGO 532603

of the gas liquids, and said he feared that the liquids would be used almost exclusively as boiler fuel at Prudhoe Bay to operate the gas conditioning plant. He urged the state to give notice of its intention to take its liquids and to negotiate with Atlantic Richfield, coordinator of the Parsons' study that outlined a design for the conditioning plant, to insure that the plan is redesigned to use less valuable fuel.

Carlson said ARCO is willing to redesign the conditioning plan to use other fuels if there is interest in buying the liquids. "Since the borough has received a proposal from Nissho-Iwai (of Japan), to purchase, in Fairbanks, as much as one million metric tons annually of propane and butane from Prudhoe Bay gas, we believe that there is strong potential interest in purchasing the liquids."

With regard to the price term of the contract, Carlson suggested that the state set the price at not less than the in-value floor, rather than having the price as a bid variable. He also suggested it might be appropriate for the state to accept less than the in-value price, "if it could be shown that the in-state sale of the royalty gas at less than in-value market prices elsewhere could insure increased state revenues and a sounder Alaskan economy through the creation of more diversified employment and business investment. It is not healthy for Alaska as a whole, nor the state government itself, if the state increases its direct revenues while major regions in the state are suffering economic distress."

When asked for his opinion on the advisability of selling the royalty gas to a promotional group this spring, Moore said, "In my judgment, you'll end up with another group like ALPETCO; you won't get a group with demonstrated competence, someone with money and markets. Is there a danger in this? Well, say ALPETCO fails. If it does fail, it will fail two years in the future and by that time, 10 per cent of the productive life of the field will be gone. By the time someone else gets a chance, it may be too late. This is sort of a one-shot approach...I just would not ever go with someone who didn't have significant financial resources and a proven track record in the industry, and that's going to be a major company. A major company won't be attracted unless the state enhances the firmness, the tangibility of its plans."

If the state were to develop a firm design, cost estimates and financial plans for a liquids pipeline, Moore said, it would "triple, quadruple or increase tenfold" the number of companies willing at least to seriously examine the feasibility of in-state development.

"I'm not optimistic that any small, promotional company will be successful in doing something with the liquids. It's a big boys' ballgame, and they keep the little guys out."

Even if the gas were sold this year to a promotional group, Moore said, developing firm plans for a liquids pipeline is still a good idea. "The promoters would have an easier time if you did that. It would make it easier all the way around."

VALDEZ EXPECTED TO WIN APPROVAL AS SITE FOR ALPETCO

Environmental Conservation Commissioner Ernst Mueller says he knows of no "insurmountable environmental problems" that would disqualify Valdez as the site for Alpetco's planned refinery and world-scale petrochemical facility.

Mueller, in a January 17 memorandum to Natural Resources Commissioner Robert LeResche, said that while much work remains to be done to secure approval of air and water discharge permits for the Alpetco facility, the only outstanding question is whether Alpetco can meet requirements of the "Prevention of Significant Deterioration" section of the Clean Air Act.

Mueller said that based on an evaluation of Alpetco's facility design and air monitoring reports, his staff has "concluded that Alpetco should be able to comply with all air quality requirements at the Valdez site provided that they use low-sulfur gas for process heat and power, and will be able to validate air quality models to show compliance with ambient air requirements. There is no reason to assume Alpetco will be unable to meet these provisions."

About 100 Valdez residents turned out for a public hearing January 29 to tell Commissioner LeResche that the town strongly supports the facility. Lennie Boston, a DNR staffer who attended the hearing, said the testimony in favor of Alpetco was "nearly unanimous."

LeResche, who must approve or disapprove Alpetco's selection of a site by March 6 under the contract approved by the legislature last year, has said he would approve Valdez if there were no major environmental problems and the people of the area wanted it.

Revenues

OPEC PRICE INCREASE BOOSTS STATE REVENUES

While the 14.5 per cent oil price hike adopted in December by the Organization of Petroleum Exporting Countries (OPEC) evoked mostly consternation in the rest of the country, the increase is good news for Alaska.

Under the federal pricing and entitlements structure, Alaska oil can be sold for the imported price.

An analysis conducted by Al Latham of the Legislative Affairs Agency Research Division estimates that state petroleum royalty and severance taxes will be $14 million higher in fiscal 1979 due to the increase, and that fiscal 1980 revenues will be $126 million higher.

The Research Division currently is conducting an analysis of revenue projections contained in the governor's budget.

ALASKA OIL PRICES EXPECTED TO RISE ON WEST AND GULF COASTS

North Slope producers, seeking to take advantage of the Iranian oil crisis, are attempting to boost by $1 a barrel the price of relatively heavy Alaska oil sold to West Coast big buyers under long-term contracts, an industry publication reports.

Petroleum Intelligence Weekly reported January 22 that the "walloping" increase is about 40¢ more than the basic OPEC "marker" jump of 63.5¢ and would put new prices for North Slope oil between $13.65 and $13.75 a barrel delivered, compared to between $12.65 and $12.85 previously.

However, West Coast buyers are resisting the big increase and threatening to cut volumes, PIW said, and "a compromise increase of about 80¢ is generally expected to develop--equal to the basic OPEC 63.5¢ marker rise with the extra 40¢ split in half to about 20¢."

Producers originally discounted North Slope oil by 40¢ to 60¢ relative to Arab light crude in efforts to place the maximum volume on the West Coast, PIW said, since their alternative was to ship it through the Panama Canal to the U.S. Gulf at an additional cost of about $2 a barrel.

Producers have run into little resistance on their U.S. Gulf Coast sales, PIW said, despite the same $1 increase there to about $14.30 a barrel delivered.

Battelle Northwest, in an analysis recently conducted for the legislature's interim West Coast Oil Surplus Committee, concluded that "contrary to popular belief, ANS crude oil, on a world average market basis, should be valued substantially on a par with the Saudi Arabian Light marker crude or possibly slightly higher."

Battelle said that the West Coast oil surplus has been depressing the North Slope crude price for refiners not purchasing their own oil by 70¢ to $1.60 a barrel. Battelle's analysis was developed by using multiple regression techniques on 32 crude oils to determine the most likely price the international market would be willing to pay for any particular crude participating in the world market on an unregulated basis.

The consultants concluded that North Slope oil, prior to the recent OPEC price increase, would have been selling for $13.87 ± 50¢ on the West Coast were it not for the surplus. Alaska oil is being discounted in the U.S. Gulf by about 69¢ a barrel, presumably because of competition from Mexican crude, Battelle said.

Gaining the right to export North Slope crude, which is financially the most attractive option for Alaska, "could eliminate all or a large portion of the current price discounting of ANS crude," the consultants said. "Exporting ANS crude via foreign ships would also result in a reduction in the demand for Jones Act (U.S. flag) tankers and a probable reduction in rates, depending upon volumes exported."

Exploration and Development

D-2 OUTCOME WILL AFFECT OIL EXPLORATION

Whether the Arctic Wildlife Range will be opened for oil exploration, or permanently reserved as wilderness, is certain to be a controversial topic as Congress grapples with resolving d-2.

The Arctic Wildlife Range, in the extreme northeast corner of the state, is considered by some one of the most promising oil prospects anywhere in the country.

Other than decontrol of crude oil prices, no other issues have more profound, long-term implications for the oil industry than access to resources and resolution of federal land withdrawals, industry spokesmen say.

Under the d-2 compromise bill that failed to pass Congress last fall, uplands in the Arctic Wildlife Range would have been wilderness, and the coastal plain area would have been opened to limited, carefully controlled exploration under management of the Interior Department. Congressional approval would have been required to develop any oil discovered during exploration.

HR 39 passed by the House last year, and the new version of HR 39 introduced this year, would designate the range as wilderness and preclude all development.

The status of the range, currently managed by Interior essentially as a wildlife refuge, was not changed by President Carter's order under the Antiquities Act that designated 56 million acres of Alaska lands as national monuments. If Congress does not pass a bill this year, it is believed the administration will take steps to insure that the area is managed as wilderness.

CARTER PROPOSES HALT TO EXPLORATION IN NPRA

President Carter wants to conclude the multi-million dollar federal oil exploration program in the National Petroleum Reserve in Alaska (NPRA) this September, a year ahead of schedule.

Carter's fiscal 1980 (October 1, 1979 to September 30, 1980) budget request recently submitted to Congress included only $4.4 million for NPRA exploration, just enough to pay for removal of men and machines. The Interior Department is spending more than $200 million in the current fiscal year under an exploration contract with Husky Oil; about $190 million was spent in fiscal 1978.

Although the federal government has been drilling intermittently in the reserve since 1944, and extensively since the Arab oil embargo of 1973, there have been no discoveries of commerical quantities of oil.

Responsibility for managing the reserve, which was created as a Naval Petroleum Reserve by executive order of President Harding in 1923, passed from the Navy to the Interior Department in 1977.

The federal government spent about $50 million during the decade between 1944 and 1953 drilling in the reserve. Several small oil and gas fields were found during that time, including the South Barrow Gas Field that supplies the village of Barrow and the Naval Arctic Research Laboratory. Carter's budget proposal would postpone further exploration and development of the Barrow area gas field "until a comprehensive study on alternative fuel supply and distribution systems is completed."

During the energy crisis of 1973, Congress launched a seven-year exploration program that was to cost between $600 million and $700 million. The goal of the program is to establish an information base to assist Congress in determining the best use of the 23 million acre area.

An Interior Department spokesman said the decision to end drilling this year stemmed from a legislative mandate to report to Congress on NPRA by January 1980. Therefore, any information gathered in 1980 would be too late for inclusion in the report.

By this September, a total of 19 exploratory wells will have been drilled in NPRA. Seven wells planned for fiscal 1980 will not be drilled if the President's proposal prevails in Congress.

Alaska Senator Ted Stevens criticized the Interior Department "for not living up to its commitment to explore the entire area for oil and gas," according to press reports. Stevens is expected to try to increase funding for exploration when the budget reaches the Senate Appropriations Committee.

An executive of Husky Oil, the prime contractor in the USGS exploration program, said that based on work the firm has done so far, "it would be a disservice to walk away or close the area up as a wilderness and not drill more in the future."

NPRA was once considered a highly prospective area that might contain as much as 33 billion to 100 billion barrels of oil. However, the latest USGS estimate of the reserve's potential is only one to three billion barrels.

KUPARUK FIELD TO BE DEVELOPED

The Atlantic Richfield Company has told state officials it wants to produce 80,000 barrels of oil a day from the Kuparuk field near Prudhoe Bay beginning in 1982.

Although the field is believed to have a total of 3.5 billion barrels of oil in place, the physical characteristics for production are poor and it is not expected that more than 15 per cent of the oil ultimately will be recovered.

The first 20 square mile portion of the field planned for development is owned 100 per cent by ARCO; ARCO and other companies own the remaining 47 square miles of the field, which may be developed in the mid-1980s.

An ARCO spokesman said a formal "go-ahead" has not yet been received from the company's corporate headquarters, but this approval is expected by April 1.

The company declined immediate comment on whether it plans to seek an increase in capacity of the Trans-Alaska oil pipeline to accommodate the additional production, or whether the Kuparuk oil would displace some of ARCO's and other companies' production from the main Sadlerochit reservoir.

COOK INLET GAS DISCOVERY ANNOUNCED

The Simasko Production Company has announced a "significant" new gas find about six miles south of Tyonek, a Native village on the west side of Cook Inlet.

Company President Don Simasko said the formation is thought to be of commercial quantity, although it will be several weeks before its size can be estimated, the Associated Press reported.

Simasko has been conducting exploratory drilling in the area for three and a half years in conjunction with its partner, Pacific Lighting Gas Development Co., of Los Angeles. Pacific Lighting's parent company is one of the major sponsors of the Pacific Alaska LNG project, which would liquify gas from 19 Cook Inlet fields at a Nikiski plant for export to Southern California. The project has not yet received federal approval.

A Pacific Lighting spokesman said Simasko's characterization of the find "may be a bit too optimistic."

Other

MEXICAN OIL AND GAS ARE COMPETITION FOR ALASKA

The new oil and gas finds in Mexico represent major competition for Alaska's resources, a Congressional Research Service study says.

Mexican oil is expected to displace Alaska oil in the U.S. Gulf, and Mexican gas (if Mexico can be persuaded to sell it) probably would be much cheaper for Lower 48 consumers than Alaska gas brought by pipeline from the Arctic, the study said.

To the United States, the new Mexican oil represents an attractive alternative to imported OPEC oil, and the Mexican gas is cheaper than developing other "supplemental" supplies now under consideration, such as SNG, LNG and the Alaska pipeline.

Even though the United States is a natural customer for Mexico, many predict the U.S. will have to redefine its traditionally dominant

relationship with the emerging power on its southern border if it wants a secure, long-term supply of Mexican oil and gas. This may include more economic aid to Mexico, lower trade barriers on imports of Mexican textiles and produce, and a reversal of present moves toward stringent immigration controls.

While not all experts agree on the potential size of Mexico's resource base (see The Christian Science Monitor, December 4, for a pessimistic view), the predominant view is that Mexico sits on an enormous, largely unexplored sea of oil and gas. By one account, there may be enough petroleum in Mexico to supply all U.S. energy needs for 40 years at current rates of consumption.

"Intensive exploration in Mexico is turning up oil fields so immense that they could overturn the conventional wisdom about world oil supplies and significantly alter the geopolitics of energy," Science magazine reported December 22.

The numbers of "proved," "probable," and "possible" hydrocarbon reserves -- which have been revised steadily upward by Mexico for several years -- are large indeed. The Mexican government at year-end announced still another increase, setting proved reserves (based on actual drilling and development) at 40.2 billion barrels, with an additional 44.6 billion barrels probable. Total possible reserves were set at 200 billion barrels. (These figures include both oil and gas; about two-thirds are oil, one-third gas.) In contrast, the "super giant" Prudhoe Bay field has proved oil reserves of about 9.7 billion barrels, while Saudi Arabia has proved reserves of about 150 billion barrels.

According to the December 6 Congressional Research Service (CRS) report, "Mexico's Oil and Gas Policy: An Analysis," Mexico appears to have a lot of oil and gas, but "the true yield from discoveries beyond the proven reserve estimates will remain somewhat unknown until more developmental drilling takes place." Current indications, CRS said, "are that a significant hydrocarbon resource is present, perhaps in the 30 to 50 billion barrel range with the possibility of even a large amount."

One result of the large Mexican discoveries may be a reassessment of the fundamental notions underlying U.S. energy policy.

The dual premises of U.S. energy policy, as first articulated by the Nixon-Ford administrations after the 1973-74 embargo and upheaval in oil prices, are that the world is running out of energy and that the nation must curb its ravenous appetite for imported oil.

It was in the context of this widely held belief that Congress and present and past administrations decided the nation needed an expensive pipeline to transport Prudhoe Bay gas to the Lower 48.

The prospect that some of the world's richest oil fields may lie next door in a relatively friendly, non-OPEC country seems likely to further

undermine President Carter's vision of an energy crisis so serious and so imminent that it requires a response amounting to the "moral equivalent of war."

The New Republic reported in August that the CIA alerted Ford administration officials to the scale of the Mexican discoveries in 1976, more than a year before they were made public, but that both Ford and Carter ignored them in shaping energy policy because public opinion would have turned even more deaf to energy-crisis rhetoric than it already had.

Now that the administration's energy program finally has passed Congress, most signs indicate that President Carter is about to launch a campaign to secure long-term supplies to Mexican oil and gas, beginning with his visit to Mexico in mid-February.

However, the administration still is maintaining staunch public support for the Alaska gas line project, and it has placed acquisition of Mexican and Canadian supplies below all domestic sources, including Alaska gas, in its list of priorities.

At a January news conference, Carter said that there is "no short-term urgency about acquiring Mexican natural gas" because "we have at this moment a surplus of natural gas in our own country." The President observed that the Mexicans are "very independent regarding their decision on how rapidly to produce their gas and oil," and "we would not try to encroach on this independence, nor try to encourage them to more rapidly produce gas and oil than they themselves desire."

One of the President's first problems during his February visit will be to untangle the embarrassing loose ends from the natural gas sale killed early last year by Energy Secretary Schlesinger. It is widely perceived that the administration badly bungled the proposed sale of Mexican gas to six U.S. distributors at a price of $2.60 per thousand cubic feet (mcf).

Petroleos Mexicanos (PEMEX), the national oil company, had signed a letter of intent to sell the gas and had nearly completed construction on a pipeline that was to stretch from Cactus in southeast Mexico to Reynosa just south of the Texas border.

But the Carter administration refused to approve the sale, arguing the U.S. could not pay Mexico 44¢ per mcf more than it was paying for Canadian imports ($2.16/mcf). The administration also was not eager to point out the fact that its energy bill limited gas prices for U.S. producers to considerably less than Mexico was asking.

"When compared to future supplemental gas supplies available to the U.S. in the 1980's, such as Canadian imports, synthetic natural gas with naptha as a feedstock, Alaskan gas and coal gasification gas, Mexican gas appears to offer the greatest supply potential at a price with which only Canadian imports can compete," the CRS study said. "However, the political consequences surrounding the abrupt termination of natural gas

negotiations in early 1978 between PEMEX and six U.S. natural gas pipelines has made future U.S. access to Mexican gas highly uncertain."

Since the gas negotiations ended, Mexico has announced it no longer intends to export its gas to the U.S. but instead will create a nationwide distribution network to use the gas in Mexico. The U.S. refusal to accept the $2.60 price, which was based on the world oil price and calculated in terms of the Btu value of No. 2 heating oil delivered to New York, reportedly was extremely embarrassing to Mexican President Lopez Portillo and created strong political opposition in Mexico toward any hydrocarbon exports to the United States. "The idea that Mexico should tighten its belt and sell off its resources to the United States for less than the world price resulted in nationalistic outrage, particularly in view of the history of petroleum relations between the two countries," Science magazine said.

But if President Carter, who has been taking Spanish lessons for some time, is successful in smoothing relations and reopening the gas negotiations, and if agreement on a sales price ultimately is reached, the Alaska gas pipeline project could become even more uncertain.

The CRS report gives the following "reasonable estimates of supplemental gas source prices" and predicts that Alaska gas will be among the most expensive alternatives:

1985 SUPPLEMENTAL GAS PRICES (1985 dollars)

	PEMEX 1/	CANADIAN GAS 2/	SNG COAL 3/	SNG OIL 4/	ALASKA GAS 3/	LNG 5/
1985	$4.14	$3.56-5.14	$7.32-8.04	$5.00-6.75	$5.58-6.30	$5.15

1/ Assume 6 per cent annual increase in No. 2 fuel oil price.

2/ CRS estimate based on Canadian and U.S. gas pricing policy.

3/ Prices for SNG coal and Alaskan gas from DOE intervention before FERC, ANG Coal Gasification Company proceeding, FERC Docket Nos. CP75-278, et al. June 1, 1978, p.5.

4/ Estimate assumes naptha as the feedstock and is based upon conversation with Bill Norman, J. Makowski, Associates, Boston, Mass.

5/ Tenneco Atlantic Algerian project.

The export of Mexican crude oil on a large scale -- at this point considered more likely than gas exports -- also could have an impact on Alaska.

"Mexican oil will almost certainly displace a large amount of Persian Gulf oil and could displace some Alaskan oil on both the Gulf and Pacific Coasts of the United States," the CRS report said. "This could present a serious problem to Alaskan North Slope producers who have no export option and who need substantial sales in both markets in order to maintain production and pipeline throughput levels. Faced with large sunk costs and no real alternatives other than 'shutting in' capacity, these producers will probably discount Alaskan oil to whatever level is necessary to undersell Mexican oil and to maintain their market shares."

The CRS report also said the prospect of possible sales of Mexican oil on the U.S. West Coast "may aggravate the existing surplus there."

Compared to Mexican crude, North Slope oil is worth 38¢ a barrel less solely because of its lower quality.

Mexican crude is now discounted on the U.S. Gulf in order to displace Saudi light crude, the CRS report said, and this lower cost of Mexican oil already is causing North Slope crude to be further discounted by 29¢ to 58¢ per barrel in the U.S. Gulf (not counting the 38¢ quality discount). By 1985, the report said, the discount on Alaska oil in the Gulf could amount to 64¢ to $1.28 per barrel, even if the proposed Sohio pipeline from Long Beach, California, to Midland, Texas is built.

"Mexico will probably price its oil just low enough to back out Saudi light, but not low enough to displace ANS (Alaska North Slope) crude on a large scale (at the Gulf)," the report said.

By the 1990's, there's going to be a lot of Mexican oil available in the U.S. Gulf, which "will place heavy competitive pressures on all other foreign sour crude oil. If shipments of ANS crude to the Gulf Coast were reduced as a result, then the throughput of the PACTEX Pipeline (Sohio pipeline) could drop below 500,000 b/d by 1985. This could mean consequent increases in PACTEX tariffs or lead to further discounts in the price of ANS crude oil to make it competitive," the CRS report said.

"The net effect, therefore, could be one of either discouraging domestic production, especially in Alaska, or of reducing the profitability of North Slope operations," the CRS report concluded.

HAMMOND REQUESTS SUSITNA APPROPRIATION

Despite the tight state budget and general cash crunch, Governor Hammond has asked the legislature to appropriate $8.1 million to provide guarantees for studies on the Susitna hydroelectric project.

The legislature last session passed a resolution authorizing the Alaska Power Authority to sell bonds to complete a four-year, $25 million "Phase I" study, but the authorization was made contingent on passage of federal legislation that would reimburse the authority with federal funds if the project turned out to be infeasible. This legislation failed to pass Congress.

Although Senator Gravel intends to resubmit the proposal to Congress this year, it is still necessary to consider other interim financing alternatives because federal authorization would come too late to do geological, biological and engineering tests during the 1979 summer season, the governor said in a letter accompanying his proposals, SB 63 and SJR 6.

"The possibility of a one-year delay must be carefully weighed along with the many uncertainties surrounding a project which I believe will prove to meet the three pertinent criteria by which all such projects should be adjudged; is it environmentally acceptable, economically feasible and do the majority of the people desire it," the governor said.

Hammond said positive action on the appropriation is needed by mid-February in order for the Corps of Engineers to mobilize contractors and move equipment to the study sites before breakup.

"Due to the obvious complexity of the situation, including the possibility of complete State financing of the entire $25 million study effort should the Congress fail to adopt Senator Gravel's proposal, I request that you take the earliest opportunity to consider this appropriation and its companion resolution in order to satisfy yourselves that this is the proper way to proceed on this project," the governor said in his January 18 letter.

The Phase I study will address the environmental, economic, social and engineering feasibility of the massive project, which would involve construction of two dams on the Susitna River and 365 miles of transmission line. The project is now estimated to cost about $2.7 billion.

KELSO DESCRIBES PLAN TO BROADEN CAPITAL OWNERSHIP

Louis Kelso, the maverick investment banker who wants to make ordinary people rich, will soon unveil a capital diffusion plan for Alaska that, if adopted, "will be a model for other states and for every developing economy in the world."

Kelso told a group of legislators recently he recommended a similar plan to the Shah of Iran 10 years ago. "If he had followed my advice, he'd still be in power today," he said.

Kelso's recommendations for the economic and operating structure of an Alaska General Stock Ownership Corporation (AGSOC) will be made in a written report to the legislature February 15. Authorization to make the profits of an AGSOC exempt from federal corporate income taxation was granted by Congress last fall at the urging of Senator Mike Gravel.

Kelso, who met with legislators in Juneau January 25 to get "policy guidance" on the AGSOC's structure, outlined restrictions imposed by the federal law and said he thinks the restraints "are ones that the State of Alaska would favor."

The new federal law allows states to establish private corporations for the benefit of their citizens. These corporations, if they meet certain requirements, will not be subject to federal income tax. Instead, the shareholders of the corporation, which must include every qualified resident of the state who chooses to participate, will be taxed on their daily pro rata shares of the corporation's taxable income.

Restraints imposed by federal law include:

-- Shares of the corporation's stock can't be transferred for five years after their original issue unless the owner dies or moves out of the state. Kelso said he would recommend that the stock be held in escrow during the first five years.

-- No one individual can own more than 10 shares of stock.

-- At least 90 percent of the corporation's income not used for corporate operating expenses must be distributed to shareholders each year.

-- All residents of the state are entitled to a stock interest in the corporation, but they must be residents at the time the AGSOC is chartered (a date to be set by the legislature) and must remain residents until stock is issued. Kelso said Attorney General Avrum Gross is attempting to develop a definition of "resident" that will withstand constitutional challenge, but "there is no way to define it so that sooner or later a court suit won't arise."

Kelso also outlined a number of policy questions that the legislature will have to address:

-- At what age should the citizen stockholders be allowed to vote their stock? Should children be allowed to vote, or should their parents be allowed to vote for them? Kelso said he thinks it is most sensible to specify that stock would not be voted until the shareholder reaches 19, Alaska's age of majority.

-- Should an individual be required to sell his stock if he leaves the state, and if so, at what price and under what terms?

-- How should the management of the corporation be structured? Kelso said he would recommend a nine-member Board of Directors, at least five of whom would have to be Alaska residents, to be initially appointed by the governor to staggered one-, two- and three-year terms and elected thereafter by stockholders to three-year terms.

-- How should the transfer of stock be handled? Kelso said he would recommend that the corporation set up its own stock transfer department; the other alternative would be to do it through a bank.

-- How will the corporation get money for the start-up costs of hiring management, getting legal advice, and investigating investment

AGO 532615

possibilities? Kelso said between $3 million and $5 million would be needed for start-up costs, and the money could come from either a state grant or loan or a bank loan guaranteed by the state. Kelso said he prefers loans over grants because "this is intended to be a private enterprise, to pay all its costs, to stand on its own feet."

-- How will the corporation get the billions of dollars needed to invest in large projects? ("The AGSOC is designed for big projects," Kelso said. "If it took on little projects, the income would be of no significance.") Using "project financing" techniques, the AGSOC would be able to borrow from conventional lending sources, although it would have to acquire a sizeable chunk of money in equity first. The equity could be loaned by the state, or the state could guarantee an equity loan. If the loan by the state comes from a state bond issue, or if the guarantee is an unfunded liability (as opposed to appropriation of a reserve), voter approval by referendum would be required.

-- What project or projects should the AGSOC invest in? Kelso said his firm had studied one investment possibility, the Trans-Alaska oil pipeline, which "looked quite feasible." According to press reports, Senator Gravel's staff has calculated that an AGSOC purchase of British Petroleum's 16 percent interest in TAPS would generate enough earnings to pay expenses and debts and send about $390 to every Alaskan.

Kelso and others point out that even though the federal law allows GSOC's to include only residents of the state and exclude future new residents, the plan may face constitutional challenges.

An analysis conducted by the Washington, D.C., law firm of Wilmer, Cutler & Pickering for the state Department of Revenue concludes: "In light of the history of constitutional challenges to a number of Alaskan laws that have treated residents more favorably than non-residents, an eventual constitutional challenge to the state's creation of a GSOC would not be unexpected." However, the consultants said, the plan can be structured in a way "that will minimize the possibility of success of any constitutional challenge," but a favorable result cannot be guaranteed.

The analysis said the most difficult problem with the GSOC is its "closed class" feature, which limits ownership to residents on a certain date and precludes persons who later qualify as residents from becoming shareholders.

Kelso suggested that one solution might be to allow new residents to purchase AGSOC stock at book value after a two-year waiting period.

Kelso is under contract with the Legislative Finance Division and the legislature's Joint Gas Pipeline Financing Committee.

HAMMOND APPOINTS OIL AND GAS CONSERVATION COMMISSIONERS

Three current state employees were recently appointed by Governor Hammond to serve on the new Alaska Oil and Gas Conservation Commission, which was created by the legislature last session.

Hoyle Hamilton, formerly director of the Division of Oil and Gas in the Department of Natural Resources, was named chairman of the commission. Lonnie Smith, formerly chief petroleum engineer for the division, and Harry Kugler, formerly chief petroleum geologist for the division, were named as the other two commissioners.

The new commission is an independent, quasi judicial body that has assumed the division's responsibility of administering the state conservation statute. Its duties include preventing the waste of oil and gas, protecting the rights of lease holders, and issuing drilling permits on all state lands.

The commission began operation January 1.

* * * * * * * * * * *

PLEASE NOTE: THE PRECEDING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

HALLORAN

STATE OF ALASKA
THE LEGISLATURE

POUCH Y - STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

LEGISLATIVE AFFAIRS AGENCY

ENERGY BACKGROUND REPORT FOR LEGISLATORS

No. 5 April 16, 1979

CONTENTS

	Page
Oil Surplus	
Oil swap prospects suffer setbacks	1
McKinney makes case against exports	3
Sohio pulls out	5
Interior evaluates environmental impacts of pipeline proposals	7
Revenues	
Oil revenue projections rise	8
State wins victory in royalty suit	9
State audits tanker charges	10
Oil companies sue state over corporate income tax hike	11
TAPS tariff settlement proposed	11
State oil tax policies draw national criticism	12
Leasing	
Legislators question timing, preparations for Beaufort Sea sale	13
DMEM considers cash bonus bidding systems for Beaufort sale.	16
Industry urges rapid OCS development; rural Alaskans want delay	17
Gas Pipeline	
Gas pipeline difficulties continue	22
TAPS owners question proximity of gas pipeline	29
Legislature changes approval procedure for Gas Pipeline Financing Authority	30
Exploration and Development	
Wilderness vs. oil debate accelerates in Congress	32
Pacific Alaska LNG project gets favorable ruling from FERC..	35
GAO report criticizes government exploration program in NPRA; Congress debates further funding	35
Royalty Oil and Gas Development	
Alpetco outlines product slate	36
Gas liquids and royalty gas studies proposed	38
Other	
Legislature considers hydroelectric funding	38
Rural Energy Committee plans conference	39

-- Compiled by Kay Brown, Policy Analyst --

AGO 532618

OIL SWAP PROSPECTS SUFFER SETBACKS

Legislators and Natural Resources Commissioner Robert LeResche have agreed to postpone temporarily a congressional lobbying campaign for the three-way royalty oil swap with Mexico and Japan, saying they will "keep a low profile" while Congress debates a proposed extension of the McKinney amendment.

House and Senate leaders met with administration officials April 10 to discuss recent setbacks in the state's attempt to convince President Carter, the Congress and the country that foreign exchanges of Alaska royalty oil are in the national interest and should be permitted.

Representative Stewart McKinney, a Republican from Connecticut, recently introduced legislation to extend indefinitely the restriction on exporting Alaska oil and reduce the already limited circumstances under which the President could seek congressional approval for the export of domestic oil. McKinney authored the current law severely restricting exports, which will expire June 22.

LeResche and legislative consultant Arlon Tussing said Sohio's tentative abandonment of its west-to-east pipeline and the Iranian revolution have set back the state's efforts by at least six months. October is about the earliest that President Carter might propose the swap to Congress, Tussing said.

"Were it not for two things, we'd be at the point of conducting a massive congressional lobbying campaign. One of those things is the Iranian revolution, which has put the whole world oil market in turmoil and made it practically impossible for us to negotiate a swap with Mexico, because the terms keep changing all the time," Tussing said. "The Mexicans don't know how much they can get in a straight sale to Japan, so how do we structure a swap until these things settle down? Mexico thinks right now it can get $17.10 a barrel in straight sales to the United States. In that context, why would they bother going through the swap?"

If Mexico is able to get $17.10 a barrel in the U.S. Gulf, then the state should be able to get $3 a barrel more for Alaska oil sold in Japan, Tussing said, "and the swap makes the same sense as it did before."

On April 4, Mexico boosted its oil price by $3 a barrel, a 21 percent increase.

Sohio's abandonment of the PACTEX pipeline has had a negative impact on the swap's chances of winning congressional approval, Tussing said, as

AGO 532619

well as prompting "a flurry of cheap-shot demagoguery" and renewed expressions of patriotic desire for energy self-sufficiency.

"Right now I would judge that this is not the time for us to make waves with a unilateral assault on the sensibilities of Congress by trying to go ahead with a backdoor export, or trying to use some loophole in the law, or going to court," Tussing said.

Randall Moen, an attorney for the legislature's joint gas pipeline committee, urged the state to take more aggressive action by pursuing an exception in federal law that allows exchanges with the "adjacent foreign states" of Canada and Mexico. The state should complete negotiations on a swap with Mexico and Japan, apply to the Department of Commerce for an export license under the "adjacent foreign states" exception, and file suit against the government when it's rejected, Moen said. The Commerce Department interprets an adjacent nation exchange as one with "Mexico or Canada for consumption therein," Moen said, "which would preclude Alaska from any paper transaction with Mexico or Japan."

Nevertheless, Moen said, "it seems to me that if we are to be successful in the oil swap problem we must take the initiative by seeking relief through the courts, through Congress, through the President, through the Department of Commerce and Mexico. There are many ways to go about this, and we should use all means possible."

LeResche said that if the state attempts to take legal action under the "adjacent nation" exception, a restrictive version of the McKinney amendment closing the loophole is likely to become law.

Although the legislators eventually agreed to accept Tussing's low-profile strategy, several expressed concern over whether enough was being done.

"With Alpetco having a call on the oil in July of 1980, aren't we just kidding ouselves?" asked Representative Bill Miles. "Haven't we dropped the ball?"

Tussing responded that the "chances of Alpetco actually being eligible to purchase oil at that time are relatively small." Even if Alpetco does meet the requirements of its contract, he said, "it would be happy to step into the state's shoes on the swap."

Senator Bill Sumner said the state is losing $100,000 a day because of the West Coast surplus, and "I'm getting the feeling that not enough is being done."

Assistant Attorney General Bob Maynard, who has assisted LeResche in negotiations with Mexico, said it is unclear whether the Mexico-Japan swap is still economically attractive for the state. Superior Court

AGO 532620

Judge Compton's royalty oil decision means that the market must make up the difference in field charges the state will have to pay if it takes the oil in kind, Maynard said. (See page 9.)

Representative Chat Chatterton suggested the state investigate the possibility of purchasing producer oil for use in the swap to bypass this problem.

Senator Mike Colletta said he was "willing to concede that this is not the right time" to push ahead with an all-out lobbying campaign, "but in three or four months you've got to take positive action."

Tussing said he would investigate "new directions, other options," including the possibilities of swaps involving Israel and Canada, as well as continuing a "soft sell" in Congress on the state's position.

LeResche said the administration would meet with Pemex, the Mexican national oil company, at least one more time to see of the swap could be restructured under the new market conditions.

Although prospects for the swap looked promising when President Carter visited Mexico in February, congressional opposition has recently become more vocal.

Senator Henry Jackson of Washington, chairman of the Senate Energy and Natural Resources Committee and formerly a supporter of the swap, told a press conference in Seattle March 23 that the Alaska-Japan-Mexico oil swap is unlikely to win approval. "It's clear that it's not politically feasible. The Senate would not grant a waiver to the President for a swap," the Seattle Post-Intelligencer quoted Jackson as saying.

The Department of Energy has continued to express support for the swap before Congressional committees, and President Carter urged Congress to let the McKinney amendment expire June 22 in the background paper of his recent energy message, according to press reports.

MCKINNEY MAKES CASE AGAINST EXPORTS

Representative Stewart McKinney says the Prudhoe Bay oil producers have intended all along to export Alaska oil to Japan, and he's determined to stop them.

McKinney urged the Subcommittee on International Economic Policy and Trade of the House Committee on Foreign Affairs March 21 "to move this country farther down the road of self sufficiency by asking that the commitments made to this Congress in 1973 are commitments kept to this country in 1979."

AGO 532621

The oil companies "are guilty of a breach of the promise to develop a domestic distribution system for Alaskan oil," he said. McKinney also told the subcommittee that:

- Sohio's decision to cancel the PACTEX pipeline is only further evidence of the long-term intent of the North Slope producers to force exports to Japan.

- The federal government should take action forcing the oil companies to make the necessary investments to convert from processing low sulfur Iranian oil to relatively high sulfur Alaskan oil.

- In the short run, surplus Alaskan oil should be stored in the U.S. Strategic Petroleum Reserve until such refinery capacity becomes available.

- To the extent that treaty commitments exist between the United States and other countries, like Israel, exports of Alaskan oil should be permitted.

- "What would be the attitude of the constituents of the members of this subcommittee if they saw foreign flag tankers carrying Alaskan crude oil to Japan while at the same time gas stations in their communities were closed on Sunday?"

Converse Hettinger, director of the Short Supply Division, Office of Export Administration of the Bureau of Trade Regulation, Department of Commerce, said:

- It is not clear whether short-term Alaska oil exports would discourage construction of the Sohio pipeline.

- The Commerce Department believes a rigid policy banning exports could operate as a long-term disincentive for production and exploration on the North Slope.

Assistant Attorney General Robert Maynard, appearing on behalf of the State of Alaska, told the subcommittee that:

- Of the numerous restrictions on exports in current law, the state has a problem with only one, which is contained in the McKinney amendment. "The exchange we are arranging can meet this standard, but we feel it is unduly restrictive nonetheless. We oppose the requirement that an export will have a positive effect on consumer oil prices by decreasing the average crude oil acquisition costs of refiners."

- Recognizing the political problems of explaining exports to the American people in a time of oil shortage, the state is not suggesting a repeal of all export restrictions, or even a major change

AGO 532622

in existing export requirements. "We are simply advocating the beginning of a step in a direction that all seem to recognize as being in the real interest of the United States--even though it is one that public perception may not fully comprehend. We are simply asking for a relaxation of export restrictions, and the perfect opportunity is in the scheduled demise of the McKinney amendment."

Alvin Alm, assistant secretary for Policy and Evaluation, Department of Energy, told the subcommittee that the proposed McKinney amendment unnecessarily inhibits the ability of the President to make decisions in response to the energy needs and requirements of the country.

Gerald Rosen, director of the Office of Fuels and Energy, State Department, seconded that view, saying that because of international treaty provisions, such as the Sinai II Agreement with Israel and the International Energy Agency, the administration prefers minimal legislative restrictions on the President's authority to permit the export of domestic oil and consequently opposes the McKinney amendment.

SOHIO PULLS OUT

Standard Oil Co. of Ohio, the only major North Slope producer unable to sell the bulk of its Alaska production on the West Coast, apparently will not build its proposed oil pipeline from California to Texas.

Sohio officials say there is only a slim chance the project will be revived. Sohio Chairman Alton W. Whitehouse, Jr., said a "miracle" would be needed to save it.

President Carter proposed legislation to expedite the project in his national energy address April 5. Representative John Dingell, D-Mich., and Representative Morris Udall, D-Ariz., already had proposed a law that would allow Congress to pre-empt certain state and federal laws delaying the project, upon a recommendation from the president.

Whitehouse said Sohio was willing "to provide constructive assistance" for a few months "to see whether government can finally clear the way for the project to begin." But he said he doubted the Congress would pass legislation overriding California law; even if such a law could be passed, it probably could not be done in time to save PACTEX. The California legislature is unlikely to exempt the project from existing environmental laws, Whitehouse said.

"If somebody works a miracle--if lightning strikes quickly--and answers the difficult problems which remain, Sohio will reexamine the project," Whitehouse told congressional committees April 2. "But time and economics are running against all of us."

Sohio announced March 13 it would abandon PACTEX after spending four and a half years and more than $50 million trying to get approval, because of endless regulatory delays, pending and threatened litigation and erosion of the project's once-attractive economics.

The $1 billion project would have moved Alaska oil more than 1,000 miles inland from Long Beach to Midland, Texas; it was considered the leading contender among all proposals for long-term resolution of the West Coast oil surplus.

Sohio said its principal reasons for abandoning the project were:

Economic--If the pipeline had been operating in 1978, as originally projected, it would have had a cumulative throughput equal to all the surplus Alaska oil on the West Coast. After mid-1982, the remaining surplus to be moved through the line would have decreased to a level insufficient to support the economics of pipeline investment. Additional delays from litigation and obtaining final permits have pushed the startup date back to 1983.

In response to questions from Senator Henry Jackson, D-Wash., Sohio projected its 1982 North Slope wellhead netback at $6.98 for oil shipped to the U.S. Gulf Coast through the Panama Canal, compared to a wellhead netback of $7.48 for oil delivered to the Gulf Coast through PACTEX. The company said it currently has a North Slope wellhead netback of $6.01 for West Coast sales, and a $4.02 wellhead netback for oil shipped through the Panama Canal. (Figures obtained by the Legislative Affairs Agency Research Division show an average February North Slope netback of $4.56 for oil moved through the Panama Canal.)

Inflation in the cost of the pipeline and terminal due to delay also adversely affected the project's economics.

Permitting delays--After more than four years of work, Sohio was unable to obtain all of the more than 700 state and federal permits required. Almost all of the remaining unresolved questions involved environmental reviews and approvals by California state agencies. "The complexity of the issues, the number of agencies involved, and the procedural requirements of law, gave rise to a lurking fear that a final answer could not be achieved, or what is more important, that it would be impossible to predict how long it will take to secure a final answer," the company said.

Litigation--Without pre-emptive California legislation, extensive time-consuming litigation was assured. Three cases already are pending in the California courts. These suits challenge the adequacy of the basic project Environmental Impact Report (required by the California Environmental Quality Act), the approval of the California Public Utilities Commission to convert part of a natural gas pipeline into the oil line, and the validity of the Port of Long Beach lease with Sohio.

AGO 532624

Even if expediting legislation proposed by Sohio to the California legislature were passed, litigation challenging the legislation itself or actions of various California agencies pursuant to that legislation had to be expected, Sohio said. "We have been informed a number of times by several different persons of their intent to pursue legal action against this project at every possible juncture," Sohio said.

Gas pipeline availability--PACTEX would use two existing, unneeded natural gas pipelines owned by El Paso Natural Gas Co. and Southern California Gas Co. "We have recently been informed by a gas transmission company that natural gas production in the Southwest United States is not declining at expected rates, that current Canadian natural gas supplies could further increase the availability of natural gas in the Southwest and that additional supplies of natural gas may become available from Mexico. Sohio has no knowledge itself about the correctness of this assessment," Whitehouse said. The possibility the gas pipelines might be needed for gas is yet another issue that might be used to sidetrack resolution of the remaining problems.

Legislative solutions--Pre-emptive legislation overriding California environmental laws is unlikely to pass either the California legislature or Congress, the company said.

INTERIOR EVALUATES ENVIRONMENTAL IMPACTS OF PIPELINE PROPOSALS

The Department of Interior's Bureau of Land Management (BLM) is completing an Environmental Impact Statement on a number of oil pipeline proposals for moving Alaska oil eastward.

The bulk of work on the draft environmental analysis, which was reviewed at a series of public hearings in the Northwest and in Alaska this spring, relates specifically to the Northern Tier Pipeline proposal. The final EIS will be broadened significantly to include an environmental assessment of the Northwest Energy-Foothills Skagway-to-Alberta proposal, the Kitimat proposal, and the Trans Mountain Pipeline reversal, a BLM spokesman said at a public hearing in Juneau March 19.

A new law passed last fall as part of the national energy program established an expedited procedure for presidential selection of one or more of the competing oil pipelines; the law required that Environmental Impact Statements on the proposals be completed by December 1, 1978. BLM was unable to meet that deadline, but it is expediting all oil pipeline applications.

Once the EIS process is completed, the Secretary of the Interior will recommend to the President which of the pipelines should be built. The President will choose. Once a pipeline is selected, the new law provides for expedited action an all federal permits, licenses and approvals for construction and operation of the system.

AGO 532625

Most testimony at BLM's Alaska hearings on the Northern Tier draft EIS related to the Northwest Energy-Foothills proposal for a major oil port at Skagway and pipeline to Alberta. The reaction from Juneau residents was mostly negative; fishermen, conservation groups and the U.S. National Park Service questioned whether oil tankers could operate safely in Southeast Alaska waters without harming fisheries. Testimony at a March 20 hearing in Skagway was mostly positive; local residents emphasized the benefits of new jobs from construction and operation of the oil port.

Revenues

OIL REVENUE PROJECTIONS RISE

Projections of Alaska's oil and gas revenue released simultaneously on March 27 by the Department of Revenue and the Legislative Affairs Agency's Research Division both show sharp increases in fiscal year (FY) 1980.

The agency estimates that FY 1980 revenues will be about $190 million dollars more than had been estimated in January by the Department of Revenue. The Department of Revenue's March estimate shows an increase of only $90 million dollars for FY 1980. The increases are attributable principally to expected increases in pipeline throughput (from 1.19 million barrels per day to 1.35 million barrels per day) and to rising oil prices associated with the disruption of Iranian oil production.

In memoranda accompanying the estimates both the agency and the Department of Revenue emphasized the great uncertainties surrounding oil revenue projections. For example, actual FY '80 revenues could be as much as $372 million dollars higher than the January estimates if the state should get favorable rulings on the TAPS tariff and royalty pricing cases currently pending, the agency said. On April 9 the state did receive a favorable ruling on its royalty suit, but state attorneys say the matter almost certainly will be appealed.

Both the agency and the Department of Revenue said unfavorable regulatory actions or natural disasters conceivably could reduce oil revenues to levels below those estimated in January.

"The currently optimistic outlook really represents no fundamental change in the state's long-term financial position. It remains our view and the view of almost all responsible parties who have studied the issue that the 'hard landing' occasioned by the eventual loss of Prudhoe Bay revenues remains a crucial problem for Alaska," the agency said.

AGO 532626

Copies of the revenue projections issued March 27 by the Department of Revenue and the agency are available in the Research Division's office.

STATE WINS VICTORY IN ROYALTY SUIT

State Superior Court Judge Allen Compton has ruled that North Slope producers cannot charge the state for treatment and cleaning of royalty oil and gas taken in value.

The decision, issued April 9, will mean $1 billion to $1.3 billion in oil revenues alone to the state over the life of the Prudhoe Bay field if Compton's ruling is upheld on appeal. Field charges amount to $1.11 a barrel. Under an interim agreement pending settlement of the suit, the companies have been charging the state an average of 64 cents per barrel for field expenses.

The state filed the suit in September, 1977, to resolve a dispute between the state oil and gas leasing laws and the actual language of the leases.

The state argued that the Alaska Constitution and state law require that its 12½ percent royalty share be valued as oil enters the Lease Automatic Custody Transfer Meter (LACT) of the TAPS pipeline. The statute says the royalty "shall not be less than 12½ percent in amount or value of the production removed or sold from the lease." The state contended that "production" has not occurred until the oil is in marketable form, which is at the LACT meter.

The oil companies contended that the legislature delegated the authority to determine the method of valuing royalty payments to the Commissioner of Natural Resources, who exercised that authority when the leases were sold. The leases say royalties are to be valued "at the well" if taken "in value," and the companies say that means somewhere in the field before the oil has been treated.

Compton said federal court decisions support the state's contention that oil and gas cannot be deemed "produced" within the meaning of the law until the oil and gas is in marketable form. He also said the Alaska Constitution clearly states that the state's resources should be developed "to provide the maximum benefit to the citizens of the State."

If the state takes its royalty oil "in kind," however, the companies are allowed to charge the state for "cleaning and dehydrating," which is specifically authorized in the leases, Compton said.

"However, pursuant to Constitutional mandate, the State may not take royalty 'in kind' unless, after said deductions, it will be in the best interests of the State to do so, which presumably means that it will be

AGO 532627

receiving an amount at least as great as it would if the royalty was taken 'in value.' This is the only interpretation which would comport with the Constitutional requirement that the legislature develop the natural resources 'for the maximum benefit of its people,'" Compton said.

The Alpetco contract with the state for the purchase of Prudhoe Bay royalty oil specifically states that Alpetco will pay the "in value" price for oil and will reimburse the state for any costs incurred by the state solely because it took the oil in kind.

Compton's decision also applied to gas royalties, but the effect on the allocation of conditioning costs is not yet clear. Compton held that producers will have to bear all costs incurred prior to the gas entering the functional equivalent of the LACT meter into the Trans-Alaska pipeline.

Compton's decision on field costs affects roughly half the money at stake in the royalty suit. The calculation of tanker charges and other "downstream" issues have not yet been decided.

STATE AUDITS TANKER CHARGES

A study of tanker transportation economics by Martingale, Inc., indicates artificial inflation of the tanker charges claimed by some North Slope oil producers, Petroleum Revenue Director Tom Williams says.

The Petroleum Revenue Division has begun new audits of the oil companies' books as a result of the Martingale study, which was released in March.

"With respect to some of the companies, this will put their feet to the fire because they've claimed substantially higher costs than are indicated in Martingale," Williams said. "The differences are small for some companies, but there are some major differences. This puts the burden on the companies to document their costs and to rebut Martingale. They will in the course of this audit have the opportunity to come forward with evidence and supporting documents, and I don't want to prejudge their arguments."

The tanker charges for moving Prudhoe Bay oil from Valdez to the U.S. West and Gulf coasts affect the wellhead value of the oil, on which state royalties and severance taxes are based. The wellhead value is computed by subtracting the pipeline tariff, field charges and tanker charges from the destination sales price of the oil.

Whether the tanker charges claimed by the companies are too high will eventually be litigated as part of the state's royalty suit against the companies, now pending in state Superior Court.

AGO 532628

The Martingale study, prepared for the legislature and the Department of Revenue at a cost of $68,400, examines and estimates the costs for a variety of tanker arrangements used by North Slope producers for moving Prudhoe Bay oil to market.

OIL COMPANIES SUE STATE OVER CORPORATE INCOME TAX HIKE

The major North Slope oil producers, with the notable exception of Exxon, and their pipeline affiliates have filed suit against the state on grounds that the new oil and gas corporate income tax law is unconstitutional and discriminatory.

The suit, filed March 22 in Anchorage Superior Court, asks that the court prevent enforcement of the tax law passed by the 1978 legislature and order a refund of 1978 taxes paid under protest. The suit was filed by Arco Pipe Line Company, Atlantic Richfield Company, BP Alaska Inc., Sohio Natural Resources Company, Sohio Pipe Line Company--all the major North Slope producers except Exxon.

The oil industry met the Department of Revenue's March 15 deadline for payment of 1978 taxes under the new law--collectively paying $162.5 million this year.

The companies charged in the suit that the tax was tailored essentially to cover only companies owning production interests at Prudhoe Bay and is therefore discriminatory. The companies also charged that the tax violates constitutional protection against double taxation. The tax violates the equal protection and due process clauses of the Constitution because the tax bears no "fair relation" to services provided by the state, the companies claimed.

State Attorney General Avrum Gross said state attorneys researched potential constitutional challenges to the tax before the governor signed it into law last year.

"A lot of the questions are close, but it was our belief then that the court would uphold the constitutionality of it, and we believe so now," Gross said.

Petroleum Revenue Director Tom Williams said the suit may be in court one to three years before a final decision is reached.

TAPS TARIFF SETTLEMENT PROPOSED

Federal Energy Regulatory Commission Administrative Law Judge Maxwell Kane has proposed a partial settlement in the Trans-Alaska Pipeline

AGO 532629

tariff case that would substantially lower the state's cost of moving oil through the pipeline.

If the parties to the tariff case, which has been pending since the summer of 1977, agree to the settlement, the average tariff would be reduced to about $4.78 per barrel at a throughput of 1.35 million barrels a day, down from the current average of $6.21. State attorneys say oil company representatives have expressed little interest in discussing the proposed settlement.

The Legislative Research Division estimated that fiscal 1980 state revenues would be about $123 million higher if the settlement is adopted.

If the parties to the case refuse to accept the settlement, the Administrative Law Judge would make a ruling that could be appealed to the full FERC. FERC's decision could then be appealed to the federal courts.

The proposed settlement affects only "Phase I" general issues of methodology. The main issue to be resolved in "Phase II" involves the costs of constructing the pipeline.

STATE OIL TAX POLICIES DRAW NATIONAL CRITICISM

Two prestigious business publications claimed recently that unreasonable state oil taxes have impeded exploration and development of oil and gas reserves and prevented the nation from achieving energy independence.

"The clearest reason why oil companies are pulling back on further Alaskan development is the state's grab-the-money-and-run tax policies," Business Week said in an editorial February 26. "Alaskan officials...should stop treating the oil companies as the answer to all state financial needs, present and future. Sticking it to them now may look politically appealing, but in the long run it could mean less income for Alaska and less vitally needed oil for the rest of the country."

Business Week's editorial was accompanied by a lengthy cover story, "The Great Alaskan Oil Freeze," which detailed the factors--high transportation and operating costs, environmental problems, state taxes, and lack of exploration opportunities--causing the industry to leave Alaska.

Several weeks later, the Oil and Gas Journal claimed that "Alaska is no longer the plundered state--through runaway taxation it has become the plunderer."

"Alaska has erected as severe a barrier to development as the U.S. Government and the environmentalists," the March 12 Oil and Gas Journal editorial said. "It must not try to emulate OPEC's sharing of resource profits. There is a limit to entrepreneurial patience."

AGO 532630

Although oil industry spokesmen have been making the same points for a long time, the articles angered some legislators.

Republican Senator Bill Sumner of Anchorage, who opposed the corporate income tax increase on the oil industry last year, said he was concerned that "continued exploitation of one-sided facts or one-sided conclusions" may discourage some companies from future involvement in Alaska. "If I keep hearing this song sung to the extent that it is counterproductive to Alaska, the industry would have a problem with me...I'm wondering who's promoting (these articles) and I'm going to try to find out...

"I'm prepared to review the oil taxation as it relates to the oil industry in Alaska. But what I'm not willing to do is to see this thing continue, the flames of this issue continue to be fanned to the point that it creates an adverse climate which serves to the detriment of the Alaska people," Sumner said at a March 16 meeting of the Senate Resources Committee.

Oil and gas consultant Milton Lipton agreed. "I felt very distressed about the (Oil and Gas Journal) editorial, not because I think Alaskan taxation in the petroleum field may not warrant legitimate and sensible criticism, but because the conclusions that were drawn from it were so extreme and I believe so wide of the mark and so inappropriate that it rather bothers me that the Oil and Gas Journal would do a piece such as that....I don't believe that the tax regime of Alaska is driving the oil industry away from exploration in Alaska," Lipton said.

Leasing

LEGISLATORS QUESTION TIMING, PREPARATIONS FOR BEAUFORT SEA SALE

Some legislators have raised questions about the Hammond administration's preparations for the December Beaufort Sea oil and gas lease sale, the state's first major lease sale since Kachemak Bay.

At an all-day hearing March 31, the House Resources and Finance committees heard about a dozen witnesses outline environmental, legal, economic and administrative problems that should be resolved if the sale is to proceed on schedule.

Spokesmen for Exxon and Chevron urged that the sale be held in December and that a cash bonus bidding method be used. The committees plan to hold another hearing in mid-April to take additional testimony from the oil industry on its ability to overcome environmental problems associated with drilling in Arctic waters.

AGO 532631

Leadoff witnesses from the Legislative Affairs Agency research staff said that, in their view, the Division of Minerals and Energy Management has seriously underestimated the amount of work necessary to implement the new leasing law adopted by the legislature last year and is seriously understaffed for the job at hand.

Research Director Gregg Erickson pointed to recent management changes in the department as a reason for some of the problems in implementing the law. Preleasing regulations under consideration last year were dropped, Erickson said, "because of a perception on the part of the new division director, Mr. (Tom) Cook, that their adoption would even further complicate his already difficult tasks in getting state land under oil and gas lease."

Agency researchers also outlined problems that have developed in attempting to reconcile a large number of conflicting state and federal leasing laws and regulations. Issues not yet resolved include bidding methods, royalty requirements, length of leases, environmental stipulations and mitigating measures, unitization and other post-sale administrative activities, and an interim legal agreement to govern the disposition of bonuses and royalties from disputed acreage.

Spokesmen from the North Slope Borough, the area that will be most directly affected by offshore exploration in the Beaufort, said the sale is premature and should be delayed for environmental reasons. Borough Mayor Eben Hopson, who opposes any leasing beyond the Barrier Islands, said there is widespread opposition to the sale throughout the Borough and "my cooperative attitude is being maintained at increasing political cost."

Alaska Legal Services attorney Don Clocksin, representing the villages of Kaktovik and Nuiqsut and the City of Barrow, said his clients oppose leasing at this time inside as well as outside the Barrier Islands. "The basic position we take is that we do not know enough about the offshore area of the North Slope to proceed with a lease sale in that area at all at this time. We believe it is possible in the reasonably near future to have enough information, and assuming that information is positive...our clients take the position that as long as they can be assured that the activity can be done safely, their position will change and they will not oppose the lease sale," he said.

Clocksin said it is important to resolve environmental problems before leases are issued, because "industry takes the position that once they have leases, they have essentially an unalterable right to proceed with exploration and production. At the point the leases are issued, at least according to the industry point of view, we have lost much of our ability to restrict or prohibit certain types of dangerous activity."

The Department of Natural Resources did only a brief and "hopelessly inadequate" social analysis before deciding to hold the Beaufort sale, he said.

AGO 532632

Clocksin and others questioned whether the technology currently exists for the oil industry to operate safely in the ice and permafrost conditions of the Beaufort Sea, particularly in the shear and pack ice zones in the area beyond the Barrier Islands.

Dr. William Sackinger, an associate professor at the University of Alaska's Geophysical Institute, said exploration could proceed in water depths of six to 35 feet, where there is some ice movement, but "I really think that we need a much longer data base to make a proper design for a production operation in that kind of water depth." The sale area encompasses water depths of up to 60 feet.

Some witnesses said industrial activity in the Beaufort Sea may harm the area's fish, wildlife and subsistence resources, particularly the endangered bowhead whale.

Chuck Evans of the Arctic Environmental Information and Data Center said it is going to take "at least two or three years to say definitely that bowheads do not occupy those waters (proposed for leasing) at any time." It is extremely difficult to predict the effect that industrial disturbance will have on wildlife, Evans said.

Much of the testimony at the hearing centered on administrative problems with the sale, in particular whether the Department of Natural Resources had conducted an adequate economic analysis to determine which bidding methods would best maximize the value of the resource. Legislators also wanted to know whether the administration was pursuing the best legal strategy in attempting to resolve an ownership dispute with the federal government over about 19 percent of the lands in the sale area.

Legislators questioned economist-consultant Arlon Tussing on how the unresolved West Coast oil surplus will affect bidding by the companies. "...If we have a cash bonus sale, those bonuses are going to reflect a great deal of uncertainty. The companies are almost certainly going to bid on the basis of what they anticipate the price will be of the marginal barrel on the Gulf and East coasts. They're going to assume that they're not going to be able to export and there will be no pipelines. These will be on top of the discounts with respect to engineering uncertainty, taxes, inflation and so on," Tussing said.

Natural Resources Commissioner Robert LeResche said that although many things remain to be worked out, the department will complete a responsible analysis of the problems in a timely manner.

"I can tell you that if we decide the best way to (lease) the Beaufort is net profits (bidding), we'll be perfectly capable of doing it within the time frame allotted. And despite Tom Cook's earlier unfortunate remark that it would be an administrative nightmare, there are ways we can make it administrable without a lot of problems," LeResche said.

The state will be assisted by 30 or 40 federal USGS employees who already have gathered a great deal of seismic and geologic data, he said. "I personally consider that perfectly adequate preparation and data-gathering for a sale of this magnitude."

DMEM CONSIDERS CASH BONUS BIDDING SYSTEMS FOR BEAUFORT SALE

Although no final decisions have yet been made, state officials involved in planning the Beaufort Sea lease sale currently favor a system of cash bonus bidding. This system might be coupled, however, with a lease that requires the producer to share his profits on a fifty-fifty basis with the state.

The main points of this system now under discussion by personnel of the Division of Minerals and Energy Management (DMEM) in the Department of Natural Resources are:

- The state's nominal share of the net profits would be fixed at between 40 and 50 percent.
- The lease would be awarded to the bidder offering the highest cash bonus.
- Only 20 percent of the cash bonus would be required to be paid immediately, with the balance to be paid over as much as 10 years.
- Net profits payments would not be made to the state until the producer had recovered all investments in developing the tract, plus accrued interest; the bonus payment would not be counted as part of the development investment.
- The lease agreement would also provide for the payment of a minimum (12½%) royalty to the state.

Because of the allowance for capital recovery, little or no net profits would be paid to the state during the early years of production. However, the state would receive annual installments on the deferred bonus, and after production began, would also collect severance tax, the 12½% royalty, and probably income tax payments as well.

An important question not yet resolved, and one that would have significant impact on the amount of time that would elapse before the state started to collect its net profit share, relates to the rate at which the producer would be allowed to accrue interest expenses on his development costs. A relatively high rate of interest (18-20% per annum has been mentioned) would mean that a much longer period of time would elapse before the state would start to collect its net profit share.

AGO 532634

Although the net profits leasing system described above is the one currently being given the most serious consideration by DMEM, and the one that has been embodied in informal draft regulations, three other systems also have been discussed. They are:

1. The so-called "British system," which the federal government currently favors as its system of choice if a net profits arrangement is adopted on any of the federal or disputed tracts leased in the Beaufort Sea. The biggest difference between this system and the one currently preferred by the state is that no interest on development expenditures would be allowed. Instead, the producer would be permitted to recover up to twice the amount invested in development of the tract before he would be required to start paying the nominal net profits share to the government.

2. The net income tax system, under which the existing state corporate oil and gas income tax calculations would be used to determine the net profits base. Under this system payments would be much more evenly distributed over the producing life of the lease. In addition, it would eliminate the need for both the producers and the state to keep separate sets of books for net profits lease accounting.

3. The so-called "annuity system," under which the development investment would be recovered with interest over some arbitrarily selected period of time roughly corresponding with the life of the field.

Even if the formal issuance of draft regulations governing net profits leasing is deferred until mid-July, that may not be sufficient time to thoroughly evaluate the relative merits of the four possible net profits leasing schemes, and the many possible variations among and within them. The actual computer analysis of the revenue impacts of the various systems has begun in earnest, but the system currently preferred by the state is the only one on which any detailed studies have yet been completed. The choice of the net profits leasing systems selected for computer analysis will have a crucial effect on the relative attractiveness of net profits leasing to the traditional cash bonus bid system.

INDUSTRY URGES RAPID OCS DEVELOPMENT; RURAL ALASKANS WANT DELAY

Coastal communities all around Alaska want the federal government to delay oil lease sales in Outer Continental Shelf waters, local government representatives, Native leaders and citizens told state and federal officials March 27.

The subsistence lifestyle of Bush Alaskans must be protected; oil companies should be encouraged or forced to hire local residents; more

money for local planning and impact assistance needs to be appropriated; and OCS leasing should proceed slowly in a manner that will not disrupt traditional lifestyles, the officials were told.

"Our area is at a very early stage of planning," said Diane Carpenter, a member of the Bethel City Council. "We realize oil development can't be avoided; our concern is the timing.... Maintaining subsistence resources is the primary concern.... This area needs money to plan for the impacts, and we may need more time."

Governor Jay Hammond scheduled the televised "town meeting of the air" to get comments from Alaskans on the Interior Department's draft proposed five-year OCS leasing schedule.

Thirty-one nationwide OCS sales are scheduled by Interior between now and 1985; 10 of them are in Alaska. Two of the Alaska sales--in the Chukchi Sea and St. George Basin--were included in the proposed plan on a fallback basis in case other planned sales eventually are deleted. (See chart, page 20, for list of proposed federal sales.)

Three areas listed in the earlier OCS plan--Hope Basin, the Southern Aleutian Shelf and Bristol Basin--were deleted from the latest draft plan.

Comments on the draft program are due April 20; Interior will submit a revised "proposed program" to Congress by June 18. After further comment from affected states and the public, a "final" version will be sent to President Carter and Congress late next fall.

While some rural Alaskans said the schedule was too rapid, industry spokesmen complained that it was not rapid enough.

"It is probably safe to say that under the proposed schedule, some of our nation's best prospects could not be brought into production before 1995," said Bill Hopkins, executive director of the Alaska Oil and Gas Association. "It is clear that the schedule does not emphasize the goal of bringing the more promising Alaska areas into play as a hedge against Iranian-scale energy disruptions a few years down the road."

Interior officials characterized the program as an attempt to balance the nation's thirst for oil and the fragile marine environment.

AGO 532636

Industry interest in the Alaska areas proposed for leasing, and the U.S. Geological Survey's assessment of their hydrocarbon potential, are summarized in the chart below:

Oil and Gas Potential of Proposed OCS Leasing Areas

	U.S. Geological Survey			Industry Ranking[3]	
	95%[1]	5%[1]	S/Mean[2]	Resource Potential	Interest in Exploration
Beaufort Sea	0 0	7.6 19.3	3.28 BBO 8.2 TCFG	2nd of 22 areas	3rd of 22 areas
Gulf of Alaska	0 0	4.4 13.0	1.3 BBO 3.39 TCFG	17th of 22 areas	16th of 22 areas
Kodiak	0 0	1.1 3.5	0.23 BBO 0.69 TCFG	19th of 22 areas	21st of 22 areas
Cook Inlet	0.5 1.0	2.3 4.5	1.19 BBO 2.39 TCFG	16th of 22 areas	13th of 22 areas
Norton Basin	0 0	2.1 2.8	0.54 BBO 0.86 TCFG	9th of 22 areas	10th of 22 areas
Chukchi Sea	0 0	14.5 38.8	6.4 BBO 19.8 TCFG	10th of 22 areas	17th of 22 areas
Navarin Basin	0 0	1.9 4.8	0.36 BBO 0.93 TCFG	11th of 22 areas	12th of 22 areas
St. George Basin	0 0	5.1 13.1	1.32 BBO 3.37 TCFG	5th of 22 areas	9th of 22 areas

[1] These USGS probability rankings mean that, in the case of the Beaufort Sea, there is at least a 5 percent chance that no oil or gas will be discovered, and there is a 5 percent chance to discover more than 7.6 billion barrels of oil and more than 19.3 trillion cubic feet of gas.

[2] The expectation is that 3.28 billion barrels of oil and 8.2 trillion cubic feet of gas will be discovered in the Beaufort Sea.

[3] Expressed in relation to the 22 original areas throughout the U.S. (including the Gulf of Mexico, Atlantic and Pacific coasts) proposed by Interior for leasing in 1980-85.

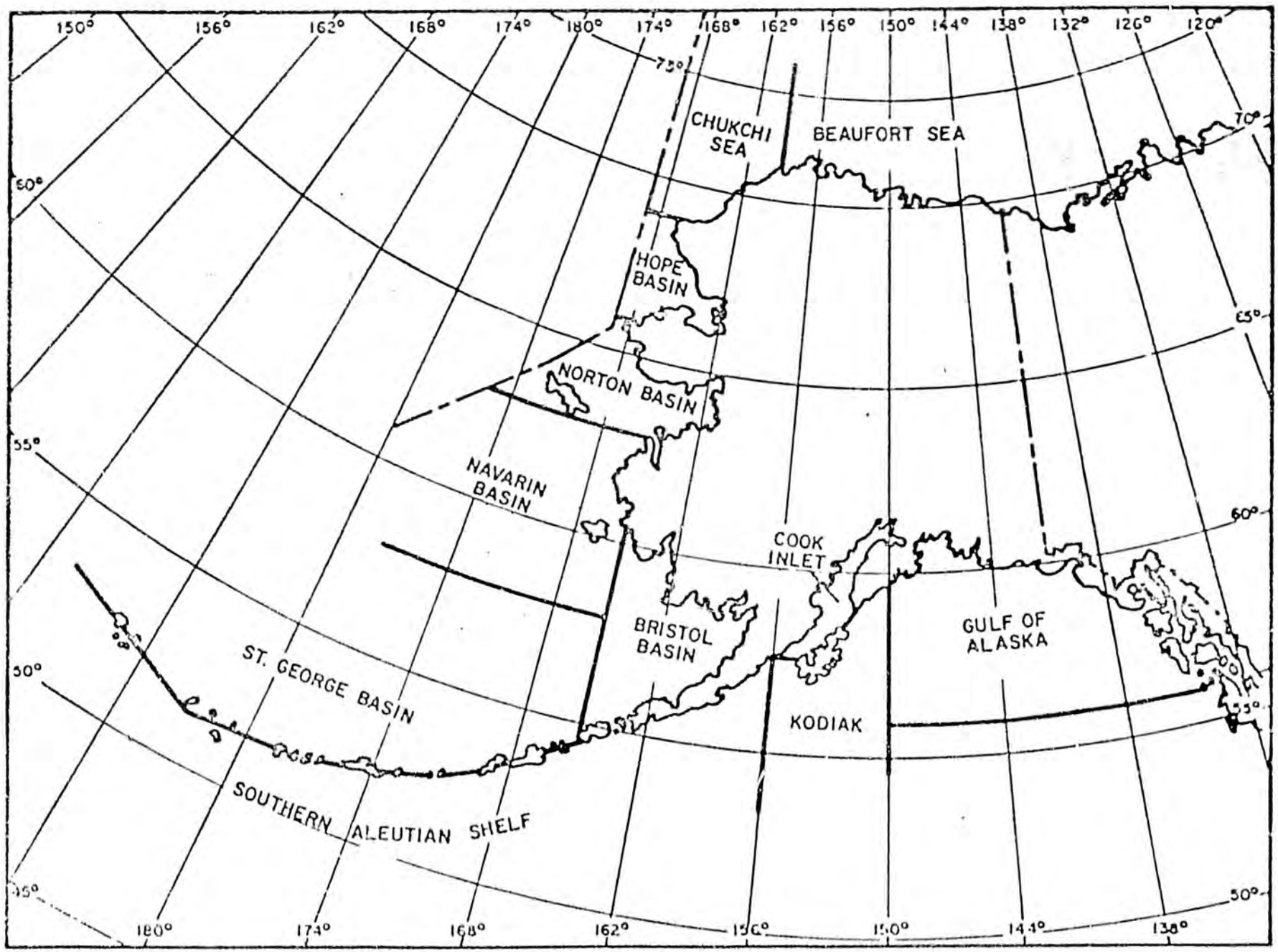
State and Proposed Federal Oil and Gas Leasing Schedules

		State	Federal
1979	July	Copper River Basin	
	Dec.	Beaufort Sea*	Beaufort Sea*
1980	Early	Arctic Slope relinquished tracts	
	Mid	Cook Inlet south of Kenai River	Gulf of Alaska (October)
	Late	Upper Cook Inlet (onshore, offshore, Susitna Valley)	Kodiak (December)
1981	Early	Lower Cook Inlet* (offshore and onshore)	
	Mid	Prudhoe Bay Uplands	Cook Inlet (September)
	Late	Norton Basin* (offshore and onshore)	
1982	Early	Beaufort Sea	
	Mid	Middle Tanana Basin Copper River Basin	
	Late	Southwest Bristol Bay uplands	Norton Basin (November)
1983	Early	Upper Cook Inlet (onshore and offshore, Susitna Valley)	Beaufort Sea (February)
	Mid	Chukchi Sea* (onshore and offshore)	
	Mid	Norton Basin	
	Late	Minchumina Basin	
1984			Cook Inlet (April) Chukchi Sea (December)**
1985			Navarin Basin (January) St. George Basin (February)**

* The state plans to coordinate these sales with the federal government.

** Contingency sales.

AGO 532638


150°
156°
162°
168°
174°
180°
174°
168°
162°
156°
150°
144°
138°
132°
126°
120°
75°
70°
65°
60°
55°
50°
45°
180°
174°
168°
162°
156°
150°
144°
138°
CHUKCHI SEA
BEAUFORT SEA
HOPE BASIN
NORTON BASIN
NAVARIN BASIN
COOK INLET
BRISTOL BASIN
GULF OF ALASKA
ST. GEORGE BASIN
KODIAK
SOUTHERN ALEUTIAN SHELF

AGD 532639

GAS PIPELINE DIFFICULTIES CONTINUE

The long list of regulatory roadblocks impeding construction of the Alaska Highway Gas Pipeline is slowly getting shorter, but the lack of a credible financing plan continues to stymie real progress.

Northwest Alaskan Pipeline Company, leader of the six-company consortium designated to build the Alaska segment of the pipeline, still publicly maintains its intent to secure private financing, as required by federal law, although it acknowledges this will be a difficult task.

Energy Secretary James Schlesinger told Congress several months ago that federal financing assistance might be necessary. President Carter, however, has not asked Congress to approve federal backstopping, and he is not expected to do so anytime in the near future.

President Carter reaffirmed his "strong commitment to the pipeline" after a meeting March 3 with Canadian Prime Minister Pierre Elliott Trudeau, but the President failed to mention the Alaska gas pipeline in his national energy message April 5. The President did finally submit to Congress his long-awaited proposal to slightly reorganize the federal bureaucracy and create the Office of Federal Inspector. The Federal Inspector, who has not yet been nominated by Carter, will have sole authority to supervise enforcement of permit regulations during construction of the Alaska pipeline.

Carter's proposal differs from the inspector envisioned in the 1977 President's Decision selecting the Alaska Highway route for the pipeline. The main difference is to strengthen the authority of the inspector by limiting appeals of his decisions.

While the federal government moved closer to getting its chief enforcement officer aboard, State Pipeline Coordinator "Mo" Mathews and more than half his staff resigned rather than move to Fairbanks.

Governor Jay Hammond promised while campaigning last fall that he would move the state inspector's office to Fairbanks to help boost the city's depressed economy. But Mathews said he didn't think the office should move until shortly before construction begins, probably in the early spring of 1982. A spokesman for the Department of Natural Resources said a replacement for Mathews probably will be named by May 1 when his resignation becomes effective.

In apparent response to pressure from the White House and Schlesinger, the Federal Energy Regulatory Commission (FERC) announced in February it would expedite progress on the unresolved tariff and Incentive Rate of

Return (IROR) issues by consolidating them in a single rulemaking proceeding. The State of Alaska objected to this procedure, claiming an evidentiary hearing is needed and an informal rulemaking is inadequate to address state concerns.

"There's been a lot of movement in the last few months. Things at FERC are heating up, and I think there's been a significant change in tone," said Assistant Attorney General Bob Maynard, who handles oil and gas matters for the state. "But it's still unclear whether all this movement means anything."

The announcement that Exxon USA and Pacific Gas & Electric Co. had completed negotiations on an agreement for the sale and purchase of about 225 million cubic feet of gas a day for 20 years was a boost for the project.

Northwest cited FERC's attempt to speed up resolution of the financial and regulatory issues as another encouraging sign of "renewed momentum." However, the regulatory logjam is far from broken.

In January, Northwest submitted a "checklist" enumerating more than 50 of the most critical items requiring immediate government action if the project is to be finished in late 1984. Yet there has been a conspicuous lack of action on most of the items, Northwest said.

"The commitment to expeditious implementation of the President's Decision with regard to the Alaskan gas project by senior administration officials is unquestioned," John G. McMillian, Northwest's chief executive officer, said in a March 20 update to Schlesinger on the project's status. "I respectfully suggest, however, that there is an urgent need to imbue such a determination at the sub-Cabinet and middle management levels."

The most pressing issues that must be resolved before June, Northwest said, include the Limited Reorganization Plan (which establishes the Federal Inspector), the commitment by the Secretary of the Interior to grant a right-of-way on federal lands, approval by FERC of system design specifications, resolution by FERC of the tariff and IROR, and final decisions on the environmental, construction and technical stipulations affecting pipeline route and design.

However, government memoranda on one pending matter--alignment of the gas pipeline in relation to TAPS--indicate that Northwest itself is responsible for a lot of the foot dragging. (See next item.)

In addition to problems on the regulatory front, no one as yet has been willing to put up the $12 billion to $14 billion needed to build the pipeline.

Consultants Arlon Tussing and Connie Barlow told the legislature in a final report, which will be released in mid-April, that the pipeline

AGO 532641

cannot be financed and built unless the United States government guarantees at least part of the project debt.

This judgment, the consultants said, "is held almost unanimously by the natural gas transmission industry, Alaska gas producers, investment bankers, lending institutions, state and federal regulators, and concerned members of Congress. The only significant dissent we encountered in more than six months of investigation came from a few top officials of the United States Department of Energy and from Northwest...the project's principal sponsor.

"Northwest thereby bears a double handicap in moving ahead on any front. Not only does it have an unworkable financial plan, but because the gas producers, potential shippers (including Northwest's own partners), state officials and important parts of the federal bureaucracy all believe the plan is unworkable, they do not sense any urgency in cooperating with Northwest or with one another in resolving even the nonfinancial issues. Because the project's financing is not credible, in other words, the whole project as presently organized is not credible," Tussing and Barlow said.

"Thus, any entreaties to the other parties by Northwest's chairman, 'jawboning' by the Secretary of Energy, or declarations of faith by the President of the United States come to nothing--they only seem to confirm what many of the parties suspected all along, that Messrs. McMillian, Schlesinger and Carter don't know what they are talking about," the consultants said.

The Alaska legislature and state administration appear firmly convinced that too many unknowns remain for the state to pledge $1.5 billion to the project at present.

Despite an ultimatum from McMillian to Governor Hammond in February, which stated that private financing would be impossible unless the state unconditionally committed $500 million in preferred equity and approved issuance of $1 billion in tax-exempt revenue bonds during the current legislative session, legislation authorizing the state commitment was never introduced for consideration in either body of the legislature.

The possibility remained that the legislature might authorize a fact-finding evaluation team, or a negotiating team, of legislators or administration officials to pursue the possibility of a direct state commitment over the interim, an approach supported by some members of the Senate and the administration.

The state House passed a non-committal resolution of support for the project in early March; House leaders subsequently informed the governor that "no further action" should be expected from the House this session on proposed negotiations with Northwest.

Nevertheless, Northwest in March kicked off a public relations and advertising campaign calculated to win support for its proposed special election on a $500 million general obligation bond issue for the project. Legislative attorneys said it probably was illegal to issue g.o. bonds for the pipeline, and it appeared unlikely the legislature would approve such an election.

Northwest released a statewide poll by the Rowan Group of Anchorage showing that from 50 to 56 percent of the 800 people surveyed approved of state financial participation in the gas pipeline.

However, a survey of Southcentral residents by Representative Randy Phillips found that 81 percent of 487 people responding to his questionnaire opposed the investment of surplus state funds in the gas pipeline.

Northwest hired a team of lobbyists to seek support in the legislature, including the governor's former executive assistant, Kent Dawson, and former state Representative Bob Bradley of Anchorage. A citizens' group headed by Anchorage businessman Les Gunderson and state Republican Party Chairman Yvonne Alford set out to get 100,000 signatures on petitions urging the legislature to negotiate with Northwest.

The issue of federal expectations for financial participation by the state government was addressed in a study by Joseph Chomski and Richard Haggart of the law firm Birch, Horton, Bittner and Monroe. The study concluded that there is not a general expectation in Washington that the state will financially participate in the project.

However, Chomski and Haggart said, the federal government possesses a large arsenal of weapons, ranging from the ability to control state oil and gas production decisions to the ability to prohibit oil exports and swaps, that could be used as leverage to force state participation.

The legislature received a wide range of advice on whether, when and how to pledge state money to the project. Alaska Senator Ted Stevens said state guarantees secured exclusively by revenues derived from the sale of North Slope gas would be a reasonable way to proceed; he said a state commitment would help assure private financing.

The Anchorage Times called McMillian's urgent request for assistance "an unattractive deal" for the state. "If the traditional financial centers of the nation find (investment in the pipeline) a bum deal, why isn't it a bum deal for the state, too?" the Times asked in a February 12 editorial.

Legislative consultant Milton Lipton said the nation's desire to tap Alaska's natural gas resources makes it very likely the pipeline eventually will be built, although "this doesn't necessarily mean that...the partners of the present Northwest consortium will be the ones that will build the pipeline." Lipton said he found it troublesome that the state

had been asked to conclude the terms of its participation before seeing how it would rank among other creditors and among other equity participants. He suggested that the state wait to see a complete financial package before making a commitment.

Some of the regulatory matters affecting progress of the pipeline are discussed in more detail below:

Conditioning costs

In early February, FERC issued a proposed rulemaking that would require North Slope producers to bear all costs of processing and conditioning Prudhoe Bay gas. FERC wants the producers to pay for these costs, estimated at 30 to 60 cents per mcf, out of the money they'll receive from selling at the ceiling price established in the new Natural Gas Policy Act. No adjustments for conditioning above the ceiling price would be allowed under FERC's proposal, except in "special hardship" cases.

FERC said this allocation of costs would enhance financeability of the pipeline, improve marketability of the gas, avoid the complications of incremental pricing, and generally be in the public interest.

In formal comments filed in March, Exxon, ARCO and Sohio strongly objected to FERC's proposal, contending, among other things, that it is contrary to Congressional intent, discriminatory and a disincentive both to production of Prudhoe Bay gas and to further exploration and development in Alaska and other frontier areas. The producers argued that conditioning Prudhoe Bay gas is a function related to transportation, not production. They urged FERC to wait for the execution and submission of gas purchase contracts before taking up the issue of gas conditioning.

The State of Alaska, making arguments similar to those advanced by the producers, said the FERC conditioning proposal was premature and was causing unnecessary confrontation and delay. The state said there is nothing in the record to support the assertion that an adjustment for conditioning costs would affect marketability of the gas. Whether the state will have to pay conditioning costs on its royalty share may be determined by the outcome of litigation now pending in state court.

The FERC staff, the New York Public Service Commission and the California Public Utilities Commission all endorsed the commission's proposed policy.

Neither Northwest Alaskan nor the Alaskan Northwest partnership filed comments on FERC's conditioning proposal. One member of the Alaska partnership, Pacific Interstate Transmission Company (which also is involved in construction of the Western Leg), said its ongoing gas sale negotiations with ARCO were suspended after FERC's proposed rule was

AGO 532644

issued. Since FERC's present position may continue to impede delivery of Prudhoe Bay gas to the Lower 48, Pacific Interstate urged FERC to reexamine its position and "permit the gas producers to collect such allowances for gathering and conditioning costs as are appropriate and justified to reflect the unique and special circumstances that exist for Prudhoe Bay gas."

Subsequently in a round of "reply comments," Exxon said its negotiated gas sales contract with PG&E provided for sale "at or near the inlet to the conditioning facility." This means PG&E could bear all, or almost all, of the conditioning costs, exactly the opposite of the FERC proposal. Observers predicted the matter ultimately will be settled in court, unless FERC reverses its current position.

On March 5, the State of Alaska filed a "freedom of information" request with FERC seeking release of all studies, documents and communications related to the conditioning issue. State attorney Robert Loeffler said he has been informed that FERC will refuse to release about 50 conditioning-related documents, and he said he is considering suing FERC over the issue. "It just doesn't seem right to me that FERC should adopt this important rule without making their documentation and records available for comment and response by the affected parties," Loeffler said.

Observers said FERC might take final action on its proposed conditioning rule by mid-May.

Tariff and IROR

FERC announced February 22 that it intended to consolidate the remaining unresolved IROR and tariff issues into a single rulemaking proceeding. A 90-page "omnibus proposed rulemaking" was issued April 6; comments on the proposal are due May 4.

The Alaskan Northwest partnership filed its proposed tariff structure with FERC March 12. The tariff document sets out the framework for rates and charges for gas transportation through the pipeline.

Alaska told the commission in formal comments and at discussion conferences that some of its concerns might not be adequately addressed in an informal rulemaking, and said it may request formal evidentiary proceedings on some issues. Alaska said it was concerned with, among other things, how tariff charges will be allocated between methane and heavier liquids, how rates will be established for new shippers in the future, how much CO_2 will be permitted in the pipeline, and how the zone tariff will be structured.

Alaskan Northwest had urged FERC to expedite consideration of the complex financial structure. The partnership said it is of "critical importance" that FERC settle the upper and lower limits for the rate of

AGO 532645

return allowed on the Alaska segment, and other related issues, by May 15 if the 1984 completion date is to be met.

Pressure and design

On March 2, the Alaskan Northwest partnership asked FERC to approve design specifications for the pipeline. These specifications designate a 48-inch pipeline with a maximum working pressure of 1260 psig, and would provide an initial capacity of 2.0 to 2.4 billion cubic feet a day (expandable up to 3.2 Bcf a day with additional compressor stations).

Alaskan Northwest said it had investigated various alternative pressures, but had concluded that its proposal was the best economic selection for delivering volumes up to 3.4 Bcf a day. Alaskan Northwest said it had considered and rejected a higher pressure system suggested by the State of Alaska that would enable movement of a greater volume of liquids for extraction and potential use in developing an in-state petrochemical industry.

Alaskan Northwest asserted that its proposed 1260 system would not impede the petrochemical development plans of the state, since this system could transport all of the ethane and propane in the Prudhoe Bay gas stream. While a higher pressure system could carry greater volumes of heavier hydrocarbons (primarily butane), these liquids would not be useful in a petrochemical plant, nor could they be transported in the Yukon section of the line.

In addition, Alaskan Northwest said, if the conditioning plant were moved to Fairbanks (as proposed by Earth Resources Co. of Alaska) and if most of the ethane and all heavier hydrocarbons were removed at Fairbanks, total deliverable energy through the project would be reduced by 20 to 25 percent. "This substantial reduction would render the project infeasible," the partnership said.

In reply comments, the State of Alaska said no evidence had been presented in the record to substantiate the partnership's claims that all ethane and propane can be carried at 1260 psig. If the partnership's assumptions are accurate, the state said, it does not object to approval of a 1260 system. However, more CO_2 should be allowed in the gas stream, and Fairbanks should not be foreclosed as a location for the conditioning plant, the state said. The project's Environmental Impact Statement will investigate Fairbanks as a location for the conditioning plant; if Fairbanks turns out to be a better place than the North Slope, the system would have to be redesigned from Prudhoe Bay to Fairbanks, the state said.

FERC is expected to approve the 48-inch, 1260-psig system in late April or early May.

AGO 532646

Western and Eastern Legs

Canada's National Energy Board (NEB) said in a report released February 28 that the country has 2 trillion cubic feet of surplus gas that can be exported during the next eight years.

This conservative estimate of Canada's gas surplus falls far short of the 8 trillion cubic feet needed to satisfy all the export applications currently on file with the NEB. One of those applications by Pan-Alberta Gas Ltd. of Calgary is linked to prebuilding of the Alaska Highway gas pipeline southern sections.

Alaskan Northwest and U.S. energy officials said the NEB report was favorable to the Alaska Highway gas pipeline project because it clearly demonstrated the limits of Canadian supplies and would add urgency to U.S. efforts to tap North Slope gas.

Alaskan Northwest is counting on prebuilding of the Western and Eastern legs of the system for the early export of surplus Canadian gas, in order to facilitate financing of the entire system.

A Canadian newspaper, The Financial Post, said the NEB report jeopardized the prebuilding scheme. "The (NEB) determined Canada simply didn't have enough surplus gas to warrant exports of the magnitude needed by the Alaska Highway (project)," the newspaper reported March 17.

Canadian officials continued to emphasize their reluctance to approve exports for the Alaska Highway pipeline's southern sections until financing is arranged for the Alaska segment.

"Canada would need to be fully satisfied expeditious construction of the whole project would proceed as planned" before allowing exports for the prebuilt sections, Peter Towe, Canadian ambassador to the U.S., said in a March speech.

TAPS OWNERS QUESTION PROXIMITY OF GAS PIPELINE

Owners of the Trans-Alaska oil pipeline say it may not be possible to build the gas pipeline alongside TAPS, as Northwest Alaskan has planned.

In a February 15 letter to Interior Secretary Andrus, the TAPS owners cited a number of factors--possible damage from blasting and equipment during construction, slope stability and soil liquefaction, erosion control and surface drainage, alternation of the hydraulic regime in rivers and flood plains, effects upon the thermal regime, below ground pipeline soil support, work pad stability, ditching effects, and hindrance to TAPS monitoring and maintenance by Alyeska--that could prevent a close alignment between the two pipelines.

AGO 532647

"The TAPS owners are not questioning the technical feasibility of constructing an Alaskan Natural Gas Transportation System. Rather, they are seriously questioning the compatibility of the gas line with TAPS.... It may be that many of the proximity issues can only be resolved on a mile-by-mile basis, i.e., at the time a notice-to-proceed is issued. It may be that the gas line cannot be constructed proximate to TAPS at any point. In any event, additional information must be submitted by Northwest before the issue of gas line proximity to TAPS can be considered," said Alyeska President Frank Turpin.

Northwest has been trying since December to secure "provisional approval" for its proposed alignment of the Alaska gas pipeline in relation to the TAPS oil pipeline; this approval is needed for Northwest to give FERC a reliable estimate on the cost of the project.

Government agencies responsible for approving proposed alignment for the gas pipeline agree with Alyeska that the information submitted by Northwest is inadequate. A joint report by BLM's Alaska Pipeline Office, the State Pipeline Coordinator's Office, the Corps of Engineers, the U.S. Fish and Wildlife Service, the Environmental Protection Agency and the U.S. Geological Survey stated: "Proposed alignment sheets and narrative description of the proposed route submitted by Northwest Alaskan Pipeline Company are inadequate to review for provisional alignment approval. Criteria for route selection was not a part of the submittal, therefore making a thorough review impossible."

LEGISLATURE CHANGES APPROVAL PROCEDURE FOR GAS PIPELINE FINANCING AUTHORITY

The Alaska House and Senate have adopted legislation that will make it more difficult for the Gas Pipeline Financing Authority to gain legislative approval to issue $1 billion in tax-exempt revenue bonds for the Alaska Highway gas pipeline.

Under the 1978 law that established the financing authority, a financial plan submitted by the authority would have been approved in 30 days unless disapproved by one house or conditionally approved by both houses.

But under an amendment sponsored by Representative Russ Meekins of Anchorage and adopted in the House April 9 by a vote of 35 to 3, the authority's financing plan would be disapproved unless approved or conditionally approved by both houses within 60 days after presentation to the legislature.

"I think we made a real mistake last year and I'm trying to remedy that mistake," Meekins said. "We reversed the normal process of this legislature.... This (amendment) puts the burden of proof on the people who want the billion dollars, and not on those who are opposed to it."

AGO 532648

The House also adopted an amendment to existing law that moved the date for submitting a financial plan back to the first day of the next legislative session.

The Gas Pipeline Financing Authority, in compliance with current state law, submitted a "financial and Alaska impact plan" to the legislature on March 14. But because of delays and other problems, the authority said a complete plan is impossible at this time and recommended that the plan be "conditionally approved."

The House adopted a resolution conditionally approving the plan; the resolution said no bonds can be issued until the plan is amended and again approved by the legislature.

No matter what the state legislature does, the authority cannot issue the tax-exempt revenue bonds unless and until Congress amends Section 103 of the Internal Revenue Code, an action many observers consider unlikely.

"A year ago when we wrote the enabling legislation, we thought that by now we would have some concise, clear answers to the question of financing the gas line, especially so far as those questions relate to the bonding authority," said Representative Bill Miles of Anchorage. "Our position is that we don't have the answers...they haven't been forthcoming, the federal government has been slow in responding and we just can't make a decision at this time. It would be absolutely irresponsible for us to do so."

But Representative Brian Rogers of Fairbanks, arguing against HB 438 that makes changes in the financing authority's procedures, said the bill "puts the House on record as favoring delaying any financing of the project, regardless of merit, for at least a year.... This bill puts roadblocks in the financing authority, and I think will delay the time when people in my district, and a lot of other districts, will be going back to work."

On April 12, the Senate adopted the amended House version of HB 438 by a vote of 13 to 5; the Senate adopted the resolution conditionally approving the financing plan by a vote of 12-7. Without action by both houses conditionally approving the plan, or action by one house to disapprove, the plan would have taken effect April 14. Some legislators wanted to prevent the plan from taking effect in its current form in order to foreclose any possibility that bonds could be issued without further legislative action.

AGO 532649

WILDERNESS VS. OIL DEBATE ACCELERATES IN CONGRESS

The coastal plain of the Arctic National Wildlife Range (ANWR) may soon play host to seismic teams and drilling rigs as well as migrating snow geese and Porcupine caribou.

The ANWR, a nine million-acre area in the state's extreme northeast corner, was established by President Eisenhower in 1960. The range is part of a larger potential oil and gas basin encompassing most land north of the Brooks Range from the Canadian border to the Chukchi Sea.

Environmentalists and the Carter administration consider ANWR highly sensitive to industrial disruption, extroadinarily pristine, and "the last place in the world" that oil development should take place.

The oil industry, pro-development interests and the State of Alaska say the area should be explored and thoroughly assessed before it is permanently designated as wilderness, where all development is prohibited.

Although proposed wilderness status for ANWR is one of the most controversial provisions of the environmentalist-backed d-2 proposals, the oil industry has other problems with them as well. Industry spokesmen argue that even though most of the state land now considered to have a "high potential" for oil and gas accumulations is outside proposed withdrawals, exploration activities generally are at a very early stage and much of the land proposed for withdrawal has not been properly evaluated. Lack of access across the withdrawals will make it very difficult to build onshore support facilities, roads and pipelines necessary to develop remote deposits, they say.

The oil industry also claims that its activity at Prudhoe Bay has had very little negative impact on delicate ecological systems and wildlife.

An orderly assessment of Alaska's resource potential, including exploration of ANWR, is a necessary and prudent step in light of the national energy crunch, the urgent need to increase domestic production and the decline of nuclear power since the near-disaster at Three Mile Island, development forces have argued.

Although not addressed specifically in the state's d-2 "consensus points," lawyer-lobbyist John Katz said the state is supporting an orderly, environmentally sensitive approach to exploration on ANWR's coastal plain. Katz said the state has not taken the lead in advocating any particular plan but "basically has been supporting what (the oil companies) have been arguing for."

AGO 532650

These arguments apparently are winning new support in the U.S. House of Representatives. The House Committee on Interior and Insular Affairs, chaired by Morris Udall of Arizona, on March 1 reported out a less restrictive bill than Udall's new version of H.R. 39. The Huckaby substitute, as it is called, would allow limited exploration of the coastal plain of ANWR.

The House Merchant Marine and Fisheries Committee on April 9 adopted a bill industry may like even better, the Breaux substitute. The measure was approved earlier by a Merchant Marine subcommittee on fish and wildlife, chaired by John Breaux, D-La. It mandates a seven-year resource assessment study of the range's coastal plain, which would include oil and gas exploration and biological wildlife studies.

Katz said the House is most likely to vote on d-2 sometime between April 30 and mid-May. Senate energy Chairman Henry Jackson, D-Wash., has said he won't begin markup in the Senate until the House has acted.

The major provisions of the pending bills as they affect ANWR are summarized below:

Udall bill (HR 39)--Sponsored by Udall and 139 other members of the House. The new HR 39 is considered by industry to be decidedly more antidevelopment than the version the House approved last session by a vote of 277 to 31. The new HR 39 would designate 84.5 million acres of wilderness, including the ANWR and some of the National Petroleum Reserve in Alaska. The bill would expand the size of ANWR by 9.9 million acres.

Durkin bill (S 222)--Sponsored in the Senate by John Durkin, D-N.H., and 17 other senators. This bill is nearly identical to the new version of HR 39.

Huckaby bill (HR 2199)--Sponsored by Representative Jerry Huckaby, D-La., and adopted by the House interior committee. This is essentially the same "compromise" bill nearly adopted last year but killed by Alaska Senator Mike Gravel at the last minute. Provisions in the bill affecting oil and gas development include:

- ANWR is not wilderness. A six-year study of ANWR's oil and gas potential would be conducted; no drilling could occur without congressional approval. ANWR would be expanded by 8.4 million acres.

- The Interior Secretary would have to make prompt decisions on whether to approve or reject lease applications in "refuge" withdrawals, which are open to oil and gas leasing under current law.

- The federal government would study the entire North Slope to ascertain oil and gas potential.

AGO 532651

- The Interior Secretary would be directed to facilitate oil and gas leasing for non-North Slope, on-shore federal lands not included in conservation units.

Breaux amendments to HR 39--Sponsored by Breaux and adopted by the House Merchant Marine and Fisheries Committee. Provisions affecting ANWR include:

- The Interior Secretary is directed to conduct a two-year study of fish and wildlife of the coastal plain, and to assess the impacts of human activities.

- The Interior Secretary has two years to adopt regulations governing exploration activity on the coastal plain; the regulations must be accompanied by an environmental impact statement on exploratory activities.

- After regulations are adopted, "any person" may submit one or more plans for exploratory activity to the secretary for approval. "Exploratory activity" means surface geological exploration or seismic exploration. The secretary must approve the plan if it is consistent with the regulations.

- Five years after the bill is enacted, any person may apply for a permit authorizing the drilling of off-structure stratographic test wells in the coastal plain. The secretary has to hold at least one public hearing in Alaska before deciding whether to issue a permit.

- Not later than seven years after the bill is enacted, the secretary would recommend to Congress whether further exploration, and development and production, should be permitted, considering the area's petroleum potential and possible adverse effects on wildlife.

Jackson bill (S 9)--Sponsored by Jackson, and essentially the same bill the Senate Energy Committee reported out last fall. This bill would direct the Interior Department to conduct an eight-year study of ANWR, including some oil and gas exploration, to determine if the area should be permanently set aside as wilderness. Congress would have 60 days to approve or disapprove a recommendation from the Interior Secretary on whether the government should conduct exploratory drilling in ANWR. At the end of the eight-year study, the president would recommend to Congress whether the area should become wilderness.

The bill would expand the size of ANWR by 5.6 million acres.

AGO 532652

PACIFIC ALASKA LNG PROJECT GETS FAVORABLE RULING FROM FERC

The Federal Energy Regulatory Commission has refused to consolidate the application of a new proposed California LNG terminal with pending proceedings of the Pacific Alaska LNG project.

Supporters of the Pacific Alaska LNG project had strongly opposed consolidation, saying that the resulting delays might be enough to kill their project.

FERC decided April 5 to deny the request of the Southern California LNG Terminal Company for consolidation of its application for a terminal at Deer Canyon, California, with that of Western LNG Terminal Associates, which has proposed a terminal at Point Conception, California.

Western's LNG terminal would receive Cook Inlet gas liquefied at Nikiski and shipped to southern California, as well as liquefied natural gas from Indonesia.

The Western LNG terminal, the Pacific Alaska LNG project, and the Pacific Indonesia LNG project are sponsored jointly by subsidiaries of Pacific Lighting Corp. and Pacific Gas & Electric Co.

The State of Alaska, the State of California and the California Public Utilities Commission supported the Pacific Alaska project sponsors in fighting the proposed consolidation. California said in comments to FERC that the majority owner of Southern California LNG (SCLNG) Terminal Company is also an owner of the Deer Canyon property proposed as a terminal site. When it became clear that Western LNG would not purchase Deer Canyon as the site for its terminal, SCLNG was formed as an allegedly competitive LNG application, California said.

California said that Deer Canyon already has been considered and rejected as a possible LNG terminal site by agencies and staffs of the State of California and the federal government.

The Pacific Alaska LNG project has been pending before federal regulators since 1974. (See Energy Background Report #3, December 8, 1978, for background on the Pacific Alaska project.)

GAO REPORT CRITICIZES GOVERNMENT EXPLORATION PROGRAM IN NPRA; CONGRESS DEBATES FURTHER FUNDING

A report by the U.S. General Accounting Office says the Interior Department's multi-million dollar North Slope exploration program has been needlessly rushed and hampered by a lack of clear objectives and definitive plans.

AGO 532653

The federal government has spent more than $600 million drilling 19 exploratory wells (all dry holes) in the National Petroleum Reserve in Alaska (NPRA) since 1974.

"We believe the exploration program is not being directed to either maximize chances for discovering hydrocarbons or provide for an overall assessment of the hydrocarbon potential of NPRA," the GAO report said. Because the program has attempted both to test major structures for commercially producible oil and gas and to obtain stratigraphic data for the entire 37,000 square miles of the reserve, neither goal has been accomplished.

The program has been rushed by Congressional deadlines of April, 1979, and January, 1980, for completion of studies on the reserve's oil potential and future uses. The GAO recommended in its December report that Interior develop an explicit plan for further exploration, seek an extension of the study deadlines, and consider allowing private industry to conduct any additional exploration and development as a way to cut costs.

The Carter administration apparently ignored the report in recommending to Congress that drilling be halted this September, a year ahead of schedule. "My personal recommendation is that we put it on the shelf and wait to see if it is needed," Interior Secretary Cecil Andrus told a congressional committee.

But the administration's proposed cutback has met stiff resistance in Congress, and it appears likely money will be added to the fiscal 1980 budget for the exploration and assessment program.

Representative Morris Udall of Arizona joined the Alaska congressional delegation and others in support of continued drilling. "In my attempts to prevent oil development of the Arctic Wildlife Range, I point out there are plenty of other sites in Alaska for oil exploration and production," Udall said. "One of those sites is the NPRA."

Alaska Senator Ted Stevens called the administration's plan to end exploration "one of the worst decisions I've ever seen in my years in government" and threatened to use it against President Carter in the 1980 presidential campaign.

Royalty Oil and Gas Development

ALPETCO OUTLINES PRODUCT SLATE

ALPETCO, which has a contract to purchase Prudhoe Bay royalty oil for use in its planned refinery and petrochemical facility, says gasoline and jet fuel will be its principal products in the early years of operation.

ALPETCO President Gordon Cain appeared before the Senate Resources Committee March 8 to brief legislators on the company's progress since last June. ALPETCO is moving ahead with the design and configuration of a facility that will meet environmental and marketing considerations, he said.

Cain said the company's preliminary product slate includes principally no lead gasoline, regular gasoline and jet fuel. The facility also will make enough diesel fuel for the Alaska market, a small amount of heavy fuel oil for sale in the Alaska market three aromatics (benzene, toluene and xylenes), naptha (which eventually will be used as a feedstock for ethylene production), some carbon black and sulfur.

The plant configuration and product output were determined by considerations of (1) the North Slope crude, which is heavy and high in sulfur content, and (2) the West Coast market, which has a surplus of residual fuel oil and little demand for home heating oil, Cain said. Cain stated that the presently proposed plant design and output would help solve critical problems, because (1) ALPETCO will produce no lead gasoline, which is in short supply; (2) ALPETCO will not contribute to the West Coast residual fuel oil surplus; and (3) ALPETCO will use 150,000 barrels a day of crude which otherwise would have been surplus on the West Coast and would have to be shipped to the East Coast at considerable cost.

When questioned, Cain said he anticipated that downstream petrochemicals, such as styrene, phenol and ethylene products, would come on stream two years after the refinery/petrochemical complex had been in operation.

Cain indicated that the fuels products would be marketed on the West Coast, and the petrochemicals would be sold in Japan, South Korea and Taiwan, as would be the naptha, provided an export permit could be obtained.

ALPETCO and its environmental consultant are continuing to work closely with the Department of Environmental Conservation and the Environmental Protection Agency in the preparation of the draft Environmental Impact Statement, which is due in October of this year.

Cain said ALPETCO expects financing arrangements for the facility to be completed in the near future. ALPETCO believes it will have long-term contracts for 90 percent of the product output signed by mid-summer, he said.

As expected, Natural Resources Commissioner Robert LeResche approved Valdez as the site for the proposed facility on March 5.

GAS LIQUIDS AND ROYALTY GAS PIPELINE STUDIES PROPOSED

Appropriations for engineering feasibility studies of gas liquids and royalty gas pipelines from Prudhoe Bay to tidewater appear likely to be approved by the legislature this session.

The Senate unanimously approved a $275,000 appropriation (CS SB 128) March 19. The Senate bill would give the Legislative Council $200,000 to be used by the Senate Resources Committee in studying the engineering feasibility of a gas liquids pipeline, and $75,000 to be used by the Legislative Council Interim Committee on Rural Energy Policy in evaluating the benefits of in-state use of royalty gas.

A similar House measure (CS HB 239) appropriating $450,000 for gas liquids and royalty gas pipeline studies has been approved by the Resources and Finance committees, and is pending in the Rules Committee. The House bill is sponsored by 33 members.

Consultant Joe Moore of Bonner & Moore Associates, Inc., earlier recommended an engineering feasibility study of a gas liquids pipeline as a way to help the state promote development of a petrochemical industry. (See Energy Background Report #4, Feb. 1, for details.)

Other

LEGISLATURE CONSIDERS HYDROELECTRIC FUNDING

An $8.1 million appropriation to fund feasibility studies for the Susitna hydroelectric project, and a $7.3 million appropriation for four other hydroelectric projects, are pending in the legislature.

The Senate in February approved an $8.1 million special appropriation to the Alaska Power Authority to be used as a reserve to guarantee tax-free revenue bonds for Susitna Phase I feasibility studies, which will cost at least $25 million.

The Internal Revenue Service said in March it would not approve the authority's financing scheme; the authority then began examining other approaches in an attempt to keep the four-year Phase I studies on schedule. One suggested approach was to ask voters to approve a $25 million general obligation bond issue for the studies, but questions were raised about the legality of issuing g.o. bonds for studies.

The authority decided April 9, based on recommendations from the governor's Devil Canyon Task Force and interested legislators, to seek an $8 million direct appropriation from the legislature. Expenditure of the money would be contingent on one of two things happening:

AGO 532656

1. Senator Mike Gravel is successful in achieving passage of federal legislation to guarantee federal reimbursement for state money spent on the Phase I studies if the project is determined not feasible; or

2. If Senator Gravel fails to get such legislation passed, a reasonable alternative program has been developed to construct the project without federal participation.

"Absent some completely unforeseen event occurring, the general fund would be the only source of funds available to finance either approach, but might be paid back if Gravel's plan is approved," the governor's task force said in a memo. "In either proposal, the money required could become part of the project financing if the project is constructed."

The authority will develop alternate approaches, considering construction by both the Army Corps of Engineers and private firms, between now and the end of the 1979 congressional session, said Terry McGuire, a financial adviser to the authority.

McGuire said the problems in designing a workable and legal financing plan have put the project substantially behind schedule. The authority earlier had requested prompt legislative action so the corps could proceed with field engineering studies this spring and summer. Some of the lost year can still be salvaged if the appropriation is approved quickly enough to get biological studies underway by summer, McGuire said.

The Susitna appropriations bill and a companion resolution are pending in the House Resources Committee.

The House already has approved $7.3 million for the Alaska Power Authority's revolving fund for hydro projects in Ketchikan ($3.1 million), Kodiak ($2 million), Cordova ($250,000) and Wrangell-Petersburg ($2 million). Those appropriations are pending in the Senate Finance Committee.

RURAL ENERGY COMMITTEE PLANS CONFERENCE

The Legislative Council's Rural Energy Committee is planning a conference on state energy policy alternatives May 16 and 17 in Anchorage.

The committee, chaired by Senator Frank Ferguson of Kotzebue, has retained Alaska Native Foundation President Roger Lang under a $48,000 contract to organize the conference, which will bring together consumers, planners, regulators, producers, utility companies and others concerned about developing a long-range state energy policy.

"There's no plan now," Lang said. "Our plan seems to be to move our oil and gas resources out of the state as quickly as possible. Is that what people want? ...Citizens ought to be getting some benefit from these resources besides money into the state treasury."

Lang said he expects that issues such as the high cost of home heating, the lack of in-state oil and gas delivery systems, and the role of coal and hydroelectric power will be discussed at the conference.

The committee plans a second meeting in September or October to develop recommendations for the governor and the legislature based on the findings of the May conference, Lang said.

AGO 532658

PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

AN OVERVIEW OF NATURAL GAS AND GASLINE ISSUES

By Kay Brown, Assistant to Senate President John L. Rader

and

Connie Barlow, Assistant to Natural Resources Commissioner
Robert LeResche

April 20, 1978

(Updated and revised June 2, 1978)

Published by

Legislative Affairs Agency

AGO 532659

TABLE OF CONTENTS

CHAPTER

I. Introduction.....1

II. Who is Involved?.....3

III. Engineering and Scientific Considerations: Pipeline Design and Field Activities.....27

IV. Economic Considerations: Pipeline Financing, Gas Pricing and Tariffs.....43

V. Timing and Relationships of Gasline Events.....66

VI. Immediate State Concerns.....69

REFERENCES.....84

AGO 532660

I. INTRODUCTION

Throughout this year and next the legislature and several agencies within the executive will be confronted by two major issues relating to the proposed Northwest Gas Pipeline.

(1) What should the State do with its royalty share of Prudhoe Bay gas?

(2) What role should the State play in financing the proposed pipeline?

Not only might these decisions affect billions of dollars of State money, but the underlying facts, principles, and relationships are extremely complex--and to a large extent unknown. As a result, the spectre of dealing with these issues becomes downright formidable.

This paper is an attempt to lay out these facts, principles, and relationships in a comprehensible fashion. It attempts to touch on the full range of gasline considerations and to unravel these inter-relationships. It also is designed to supply the technical tools by which each issue can be approached.

A grasp of the engineering and economic principles is essential; but once this is surmounted, the policy considerations can and must be explored.

Note: This report was updated and revised on June 2, 1978. For that reason, references made to the "Overview" memorandum

AGO 532661

in the Bache Halsey Stuart Shields consultant report ("Analysis of Proposed Financial Support for Northwest Alaskan Natural Gas Pipeline Project," May 24, 1978) do not correspond to page numbers in this document.

AGO 532662

II. WHO IS INVOLVED?

The principal actors in the gasline debate are:

Gas producers and owners

Gas purchasers

Gas transportation (pipeline) companies

Investors

Government regulators

Landowners

GAS PRODUCERS AND OWNERS

A. Gas Producers

The Prudhoe Bay producers are those companies which hold State leases for oil and gas resources on the North Slope. Since geologic conditions mean individual producers draw oil and gas from a common pool (Sadlerochit), allocation of produced oil and gas was negotiated and set forth in a Unit Agreement. Practically all of the oil and gas production is allocated to three companies: SOHIO, EXXON and ARCO.

AGO 532663

OIL & GAS PRODUCERS

Company	%Gas Cap Gas[1]	%Solution Gas[2]	%Total Gas[3]	%Total Oil
SOHIO	15%	53%	27%	53%
ARCO	42%	20%	36%	20%
EXXON	42%	20%	36%	20%

1/ Gas cap gas is produced from the gas layer which rests on top of the oil zone. This gas is produced only when a decision is made to withdraw gas from the gas cap. Such a decision would only be made when the gas is intended for sale.

2/ Solution gas is the gas dissolved in the oil which is necessarily produced with the oil. Until sale arrangements are made for this gas, it must be reinjected, flared or used as fuel for field operations.

3/ Total gas production is based on DNR estimates of producible gas cap gas of 19.5 trillion cubic feet and producible solution gas of 8.0 trillion cubic feet (gas cap=70%; solution=30%), and represents the weighted average of each company's respective allocation of gas cap gas and solution gas.

B. Gas Owners

The producers are all owners of North Slope gas. While not a producer, the State of Alaska is also a gas owner by virtue of a clause in the lease agreements which entitles the State to a 12 1/2% royalty share. Hence, the real ownership of Prudhoe Unit gas is as follows:

GAS & CRUDE OWNERS

Owner	%of Gas Cap and Solution Gas	%Oil
SOHIO	23.5%	46.5%
EXXON	31.5%	17.5%
ARCO	31.5%	17.5%
STATE OF ALASKA	12.5%	12.5%

AGO 532664

GAS PURCHASERS

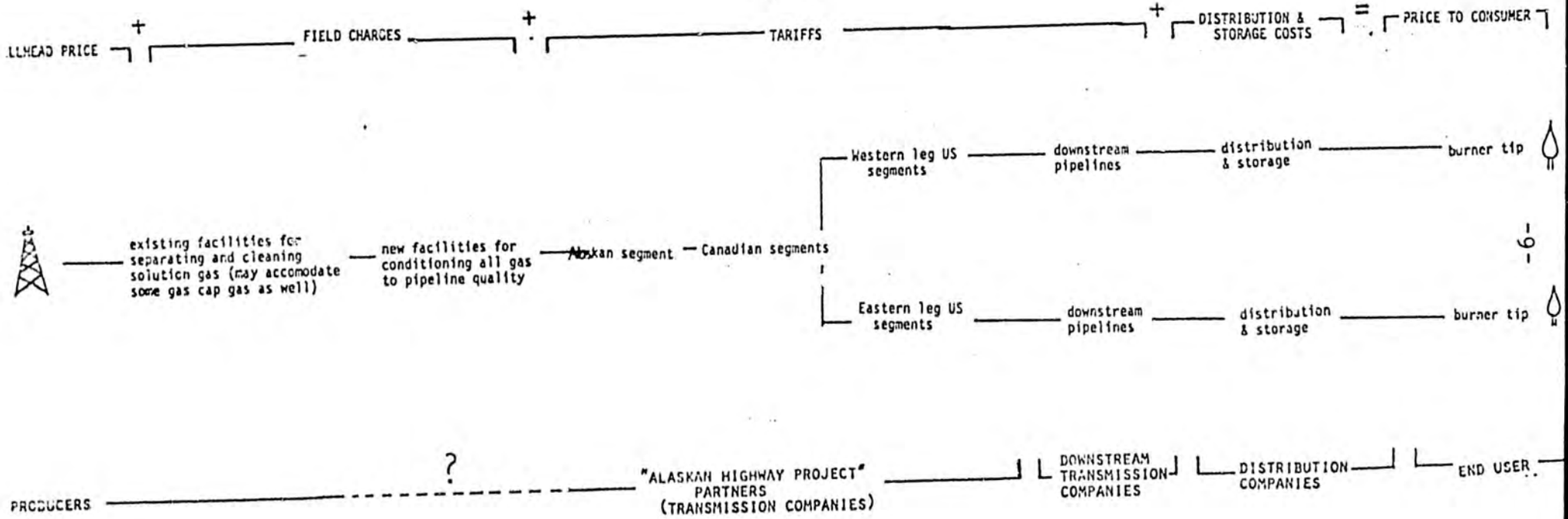
A. Potential Purchasers

The marketing of Prudhoe Bay gas is very different from that of oil. To a large extent the Prudhoe producers are both buyers and sellers of North Slope oil. For example, Exxon is an "integrated" oil company, and it is, therefore, in Exxon's interest for its production arm to "sell" oil to its refining subsidiaries. On the other hand, the major oil companies have never been involved in gas transportation and marketing beyond the field. Gas was historically a nuisance by-product of oil production destined for flaring.

The purchasers of North Slope gas, instead, will be gas distribution companies and interstate gas transmission (pipeline) companies with established fuels markets. End consumers purchase gas from these companies for commercial and residential heating, power generation by electric utilities, and industrial use as boiler fuel, process gas and petrochemical feedstocks. (See attached chart.)

TRACKING THE FLOW OF GAS FROM THE WELLHEAD

TO THE CONSUMER BURNER TIP



AGO 532666

Customers who use the gas for heating and power are primarily interested in "dry gas" (composed of methane, which is abbreviated C^1). This is the type of gas produced in Cook Inlet and used in Anchorage households. However, North Slope gas is "associated" with an oil reservoir and therefore also contains heavier hydrocarbons (C^2, C^3, C^4 - ethane, propane, butane) which can be burned as fuel but have alternative uses as petrochemical feedstocks for the production of plastics and other man-made materials. As such, these gas "liquids" may attract purchasers from the petrochemical industry, either those interested in locating a new facility in Alaska, or those with existing plants elsewhere along the pipeline route.[1] Dry gas and gas liquids can either be sold separately to different purchasers or in combination to a single purchaser.

The State might also play the role of a gas purchaser if it chooses to negotiate a trade with the producers. A portion of its royalty share of dry gas could be offered for sale to enable purchase of producer liquids, if this would provide a more attractive volume and type of resource for encouraging petrochemical development in Alaska.

1/ Fertilizer companies and fuels companies may also be interested in the methane for production of ammonia/urea or methanol.

POTENTIAL PURCHASERS

Interstate Gas Transmission Companies

Gas Distribution Companies

Petrochemical, Fertilizer and Methanol Companies

State of Alaska

B. Conditions Affecting Sales to Purchasers

Which, if any, of the above potential purchasers will eventually sign gas purchase contracts depends, in part, upon economic considerations. The considerations include what price gas owners view as acceptable, and how much the purchaser is willing to pay (taking into consideration other gas sources or alternative fuels). In addition, if demand surpasses available reserves, competition may weed out certain types of purchasers.

However, sales will also be affected by State and federal intervention. On the State side, the State as royalty owner may grant a sale preference to a particular purchaser, such as a petrochemical company or Alaskan gas distribution company, so as to meet goals other than strict monetary return.

On the federal side, FERC retains powers over those gas sales. While FERC's jurisdiction is technically complex[1], the

1/ FERC has approval authority over "sales for resale in interstate commerce," and it authorizes the use of pipeline capacity over any sale, regardless of whether it possesses direct sale approval powers.

AGO 532668

end effect is that FERC can assert power through some mechanism over virtually any sale of gas which uses an interstate line. FERC can exercise this power freely to accomplish any defensible public purpose.

In addition to FERC's normal powers, the President's Decision, as approved by Congress, clearly charges the Secretary of Energy to use his or her approval authority to ensure equitable distribution to all parts of the country. If producer/purchaser negotiated sales result in a West Coast/East Coast market ratio vastly different from 30%/70%, FERC is empowered to require adjustments in sales.

CONDITIONS AFFECTING SALES TO PURCHASERS:

Economic/Marketing

State Policy for sale of its royalty gas

Federal regulation:

FERC authority to approve sales
DOE authority to approve East/West distribution of sales

TRANSPORTATION COMPANIES (Pipelines)

This whole gasline question came to the fore because three competing consortiums of interstate transmission and distribution companies (originally, Arctic, El Paso and Alcan) approached FERC for approvals to construct a pipeline to transport gas from Prudhoe Bay to the Lower 48.

AGO 532669

A. Gas Purchasers' Involvement in Pipeline Ownership

It is an open question whether potential gas purchasers have taken the lead in securing Alaskan pipeline ownership positions because they need to ensure a means to transport purchased gas to market, or because they view an equity position as a worthwhile investment in and of itself. Unlike most gas pipelines in which transport of gas is at the sole discretion of the owners, the Alaska gasline will be a "common carrier," meaning equal opportunity for gas shipments must be afforded all interested parties (just like the TAPS oil line). Hence, a gas purchaser who owns a piece of the pipeline gains no special benefits with respect to transportation access than does a non-pipeline owner. In regard to the desirability of pipeline ownership as an investment, the Alaska project has several unique features which may detract from the usual desirability of earning an assured rate of return as a regulated utility. These factors include the tremendous scale and technological uncertainties of the project, the uncertainty of delivered throughput and the imposition of a "variable rate of return" which subjects a company's profits to the risks of cost overruns. It appears likely that the opportunity to achieve a higher than normal rate of return will have to be afforded in order to compensate for these additional risks.

B. Gas Owners' Involvement

1. The Producers - Producers will not join the pipeline consortium as equity owners for two reasons. First, as previously mentioned, the integrated oil companies have

AGO 532670

traditionally avoided downstream transportation and marketing of gas produced in association with oil. Second, the President, in his decision, specifically opposed producer participation in pipeline ownership, due to real or imagined anti-trust considerations raised by the Justice Department in its July, 1977, report to the President.

2. The State of Alaska - The President's Decision cast the State as a beneficiary of the pipeline, and assumed that the State would therefore find it in its interest to participate in pipeline financing, including consideration of investing risk capital in an equity position. The report argued that the State, like the producers, would benefit from the pipeline in that a pipeline would facilitate the sale of its royalty gas. In addition, the State stood to gain from an increased tax base, economic development, and jobs. Unlike the producers, the federal government appears to have found no anti-trust problems with State involvement in pipeline ownership.

C. Federal Government Involvement in Pipeline Ownership

It can be argued that the federal government has an interest in assuring the marketing of Prudhoe gas, so that its goals with respect to energy self-sufficiency through increased domestic production of oil and gas are met. However, the President and Congress have specifically mandated that no federal participation will occur. Congressional action would be required to change that decision. The decision was based on several factors, including a concern about risking taxpayer capital for the benefit of gas consumers, and a fear of setting a precedent for federal involvement in other large-scale energy projects.

POTENTIAL PIPELINE OWNERS

Gas Purchasers (Pipeline and distribution companies)

State of Alaska

D. The Composition of the "Alaska Highway Pipeline Project"

The "Alaska Highway Pipeline Project" (formerly Alcan) is a loose consortium of nine U.S. and Canadian companies, each with their own membership structures. These nine companies are organizing to construct eleven separate parts of the Pipeline Project which begins on the North Slope and ends in Illinois ("Eastern Leg") and California ("Western Leg"). These nine companies can, therefore, be expected to file at least eleven separate tariffs with the appropriate U.S. and Canadian agencies. The following pages portray these pipeline companies and their jurisdictions along the pipeline route.

The names of these pipeline companies and of their member pipeline and gas companies are a bit confusing. For example, "Alaskan Northwest" is the name of the newly formed company in charge of the Alaskan segment of the pipeline. "Northwest Alaskan" (a subsidiary of Northwest Pipeline of Salt Lake) is one of the six member companies of "Alaskan Northwest."

Some of these pipeline companies have been in existence for a long time (such as Pacific Gas and Electric), and are included in the Pipeline Project because they will be "looping" their existing lines[1] in order to carry the North Slope gas. Others, like Alaskan Northwest, are organizing as new pipeline companies

1/ "Looping" entails laying additional pipeline alongside an existing line to increase capacity.

(generally composed of new subsidiaries of existing pipeline and distribution companies) and will be laying pipe along routes where no gaslines now exist. These latter types of companies are continuing to develop their membership structures which will probably remain in flux until gas sales are consummated.

ORGANIZATION OF THE "ALASKA HIGHWAY PIPELINE PROJECT"

(1) Alaskan Northwest Natural Gas Transportation Company

members: Northwest Alaskan Pipeline Company ("operating partner")
(subsidiary of Northwest Pipeline Company, Salt Lake)

Northern Arctic Gas Company
(subsidiary of Northern Natural Gas Co, Omaha)

Pan-Alaskan Gas Company
(subsidiary of Panhandle Eastern Pipeline Co, Houston)

United Alaska Fuels Corporation
(subsidiary of United Gas Pipeline Co, Houston)

* Natural Gas Corporation of California
(subsidiary of Pacific Gas and Electric, San Francisco

Pacific Interstate Transmission Company
(subsidiary of Pacific Lighting Corp, Los Angeles)

(2) Pacific Gas and Electric (existing company)

(3) Pacific Gas Transmission Company (existing company)

(4) Northern Border Pipeline Company (currently being organized by Norchern Natural Gas Co, Omaha)

(5) Foothills Pipeline (S. Yukon) Ltd

members: Foothills Pipeline (Yukon) Ltd.[1] (100%)

(6) Foothills Pipeline (N. British Columbia) Ltd.

members: Foothills Pipeline (Yukon) Ltd.[1] (51%)

Westcoast Transmission (49%)

(7) Foothills Pipeline (S. British Columbia) Ltd.

members: Foothills Pipeline (Yukon) Ltd.[1] (51%)

Alberta Gas Trunkline (49%)

(8) Foothills Pipeline (Alberta) Ltd.

members: Foothills Pipeline (Yukon) Ltd.[1] (51%)

Alberta Gas Trunkline (49%)

(9) Foothills Pipeline (Saskatchewan) Ltd.

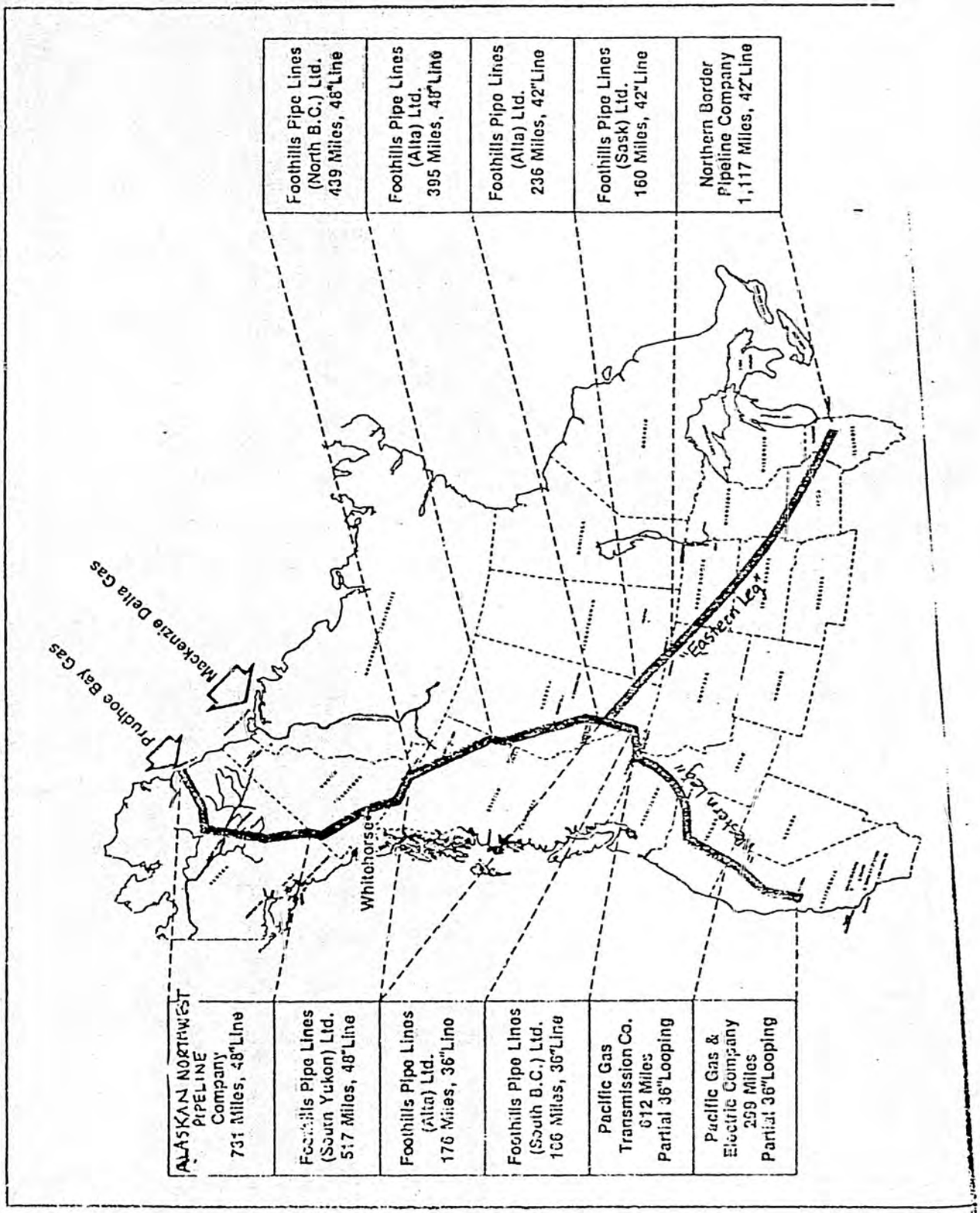
members: Foothills Pipeline (Yukon) Ltd.[1] (100%)

---

[1] Foothills Pipeline (Yukon) Ltd. maintains at least a 51% interest in each of the 5 "Foothills" pipeline consortiums. It is composed of 50% Alberta Gas Trunkline and 50% Westcoast Transmission.

AGO 532674

COMPONENTS OF THE "ALASKA HIGHWAY PIPELINE PROJECT"



AGO 532675

LENDERS

If a gas pipeline is constructed, it will mean that a sufficient quantity of equity and debt capital was raised to finance construction of the required production and transmission facilities. In addition to investment in the pipeline itself, a variety of investments (for gathering and conditioning and water injection) may be necessary in the Prudhoe field, "upstream" of the gas pipeline inlet. It will be necessary to allocate these field costs between gas production (which places the responsibility for securing capital upon the producers), and gas transportation (which places financing responsibility upon the pipeline owners).

A. Investors in Production Facilities

Equity will, of course, be provided by the producers, if the producers determine that the investment is worth the benefits to be gained at this time by sale of their gas. Debt capital would be raised from the private financial community. It is unclear as to what expectations FERC and the producers may have with respect to State participation in equity or debt arrangements. The State did not provide any capital during the construction of oil production facilities.[1]

1/ Senator Stevens at one point did advocate State participation in the conditioning facilities.

B. Investors in Transportation (pipeline) Facilities

The parties which may contribute equity as pipeline owners were discussed in the previous section on Transportation Companies. In addition to equity, there are several potential sources of debt capital.

1. Private - The private capital market is the most apparent debt investor.

2. Producers - FERC foresees investment by the producers in pipeline facilities as highly unlikely; especially since pipeline construction will necessitate concomitant field expenditures for gathering, conditioning, and water injection, much of which may be the unavoidable responsibility of the producers.

3. State of Alaska - Both the transportation consortium and the federal government are urging Alaskan investment in the gas pipeline.

4. Federal Government - The President's decision, and congressional approval thereof, prohibits debt or equity investment by the federal government.

5. The Pipeline Company - Presumably all capital (including borrowed capital) contributed by the member companies will serve as equity, as a high equity/debt ratio makes the debt investment more secure and hence easier to obtain.

POTENTIAL INVESTORS IN FIELD PRODUCTION FACILITIES

Equity: Producers

Debt: Private
State

AGO 532677

POTENTIAL INVESTORS IN TRANSPORTATION (PIPELINE) FACILITIES

Equity: Pipeline Companies
State

Debt: Private
State
Producers (highly unlikely)

LANDOWNERS

The route of the pipeline will traverse lands held by the United States, Canada, several states and provinces, municipalities and private parties. Purchase or right-of-way lease of these lands must be negotiated between the pipeline company and landowner. The gas pipeline company has a great deal more power in so doing than did the TAPS oil company, Alyeska. This is because, unlike an oil line, an interstate gas line acquires condemnation powers upon receipt of its Certificate of Public Convenience and Necessity. Alyeska's only course of action was to appeal to a government entity to condemn lands on its behalf. These gasline condemnation powers likewise extend to Canadian companies which receive certificates from Canada's equivalent of FERC - the National Energy Board.

AGO 532678

GOVERNMENT REGULATORS

United States	Canada
Congress	Parliament
Federal Energy Regulatory Commission (FERC)	National Energy Board
Department of Energy (DOE)	(Others not discussed here)
Economic Regulatory Authority	
Federal Inspector	
Executive Policy Board	
Other federal agencies	
Alaskan National Gas Pipeline Office	
State of Alaska	
State Utility Commissions	

The United States

Congress: The role of Congress in the Alaska gasline project essentially ended last November with approval of the President's "Decision and Report to Congress on the Alaska Natural Gas Transportation System," which selected the Alcan route through Canada over two competing proposals. This action was taken pursuant to the provisions of the Alaska Natural Gas Transportation Act (ANGTA) of 1976.

FERC: The DOE and FERC were created by Congress last summer. FERC is an umbrella-regulatory commission, independent and responsible to Congress. FERC was given the powers of pipeline certification formerly held by the Federal Power Commission as well as the oil pipeline tariff authority formerly held by the Interstate Commerce Commission.

In December, pursuant to provisions in the ANGTA, FERC vacated the prior proceedings before the commission (filed by El Paso and Arctic Gas) and issued a conditional Certificate of Public Convenience and Necessity to Northwest.

FERC is responsible for federal oversight of the Alcan project prior to construction. Before construction can begin, FERC must issue a final Certificate of Public Convenience and Necessity. In the course of pipeline regulation since passage of the Natural Gas Act in 1938, actions of the FPC, the courts, and now FERC have resulted in development of a considerable body of law delineating the factors to be considered in making a determination to certificate a pipeline. Analysis and a satisfactory finding are required in each of these areas before certification: financing, tariffs, marketability (including setting a wellhead rate, if necessary), gas reserves and deliverability, processing and conditioning, accounting procedures and construction cost control. In fact, FERC can impose any terms and conditions to the certificate that it finds necessary to protect the public interest.

AGO 532680

FERC also must consider environmental impacts of the project under the National Environmental Policy Act (NEPA). Having completed the EIS process, FERC's primary environmental responsibility now centers on "site specific" activities. FERC must consider and approve the location of the pipe and other design criteria which will mitigate environmental problems.

Department of Energy: The ANGTA places some responsibilities for this project in the DOE. Among these, DOE must develop an organization plan for the office of the Federal Inspector and define the relationship of that office to the Executive Policy Board (discussed below).

Joint DOE/FERC responsibilities: In addition to FERC's normal regulatory responsibilities regarding pipeline certification, the President's Decision gives FERC and DOE additional duties because of the unique nature of the project and its international implications. The required DOE/FERC areas of action include: choosing the size of the Eastern and Western legs of the pipeline, overseeing relations with Canada under the Bilateral Agreement, passing on any proposed predeliveries of Alberta gas, assessing the capacity requirements of the pipeline against the available Alaskan and Canadian reserves, and examining the proposed financing package in the light of national and international concerns of the United States.

Economic Regulatory Authority: The Economic Regulatory

Authority within DOE has the power to approve all exports and imports of gas. This means that ERA is involved in consideration of the so-called "Alberta gas swaps" in which early deliveries of Canadian gas will be made to the U.S. in anticipation of future North Slope gas being provided to Canada.

Federal Inspector: The office of Federal Inspector, created by the ANGTA, will exercise an expanded federal role in the project's management and construction. The President will appoint the Federal Inspector with the advice and consent of the Senate. Duties of the Federal Inspector include:

--establish joint surveillance and monitoring agreement with the State of Alaska;

--monitor compliance with laws, certificates, rights-of-way, permits, leases and other authorizations;

--monitor construction schedules, quality of construction, cost control, safety, environmental protection objectives; and

--keep Congress and the President informed on progress of the project.

The President's report to Congress contemplates a change in federal law to give the Federal Inspector field-level supervisory authority over the enforcement of stipulations, terms and conditions by those federal agencies having statutory responsibilities over various aspects of the project. In addition, FERC may decide to delegate its cost approval authorities to the inspector, so that acceptance of project costs for the purposes of tariff-setting will occur as the expenditures are made, rather than through the usual post-construction audit.

Executive Policy Board: The Federal Inspector will be

subject to the ultimate policy direction and supervision of an Executive Policy Board, made up of the Secretaries of the Interior, Energy, and Transportation, the Administrator of the Environmental Protection Agency and the Chief of the Army Corps of Engineers.

Other federal agencies: All federal agencies will retain their existing authorities, pursuant to ANGTA, to issue original certificates, permits, rights-of-way and other authorizations, and to prescribe any appropriate stipulations, terms, and conditions permissible under existing law. Agency Authorized Officers, representing their respective federal agencies, will directly enforce the stipulations, terms and conditions--subject to supervision by the Federal Inspector.

Alaskan Natural Gas Pipeline Office: The Federal Inspector and Agency Authorized Officers will constitute an Alaskan Natural Gas Pipeline Office.

State of Alaska: State officials (staffed by a Pipeline Coordinator within the Department of Natural Resources) will cooperate with the Federal Inspector in establishing a joint surveillance and monitoring agreement similar to the one in effect during construction of TAPS. In addition, the State's regulatory authority will include these areas:

--Conservation laws: The State Department of Natural Resources, Division of Oil and Gas Conservation, and the Alaska Oil and Gas Conservation Committee (within DNR) have the statutory power to "prevent waste" of oil and gas produced in the State. This authority is a key factor which will determine how much gas is available for shipment through a pipeline. Pursuant to this authority, the Conservation Committee last

23 What about Economic Waste?

June issued Conservation Order No. 145, which approves an operating plan for the Prudhoe Bay field. The order approves offtake of 2.7 billion cubic feet a day of raw gas (which would yield pipeline quality gas of 2.0 bcfd) and declares that this offtake is "consistent with sound conservation practices based on currently available data." The order also says that "large scale source water injection will probably be necessary to maximize oil recovery." However, it does not make production of gas contingent on the installment of water injection facilities by the producers. "The offtake rates approved by the Committee at this time must be established without the benefit of production history," the order says. "Therefore, these offtake rates may be changed as production data and additional reservoir data are obtained and analyzed."

O. K. "Easy" Gilbreth, Director of the Division of Oil and Gas Conservation and chairman of its Conservation Committee, told a congressional committee last fall that the State believes "there is no sound technical reason to delay, provided that the operators adopt and implement a source water injection program by the time gas sales start. If the operators do not implement a source water injection program, then gas sales will have to be limited or postponed in order to avoid jeopardizing ultimate oil recovery."

Although the State has the authority to shut-in or reduce gas production to prevent waste, some fear that it may be practically or politically impossible to take such an action once the gasline is under construction or in place.

AGO 532684

A bill pending in the Legislature (CSHB 830) by Representatives Chat Chatterton and Hugh Malone would transfer the State's conservation authority from the Department of Natural Resources to an independent agency.

--Right-of-way Leasing Act: Northwest will make application to the Department of Natural Resources seeking right-of-way certificates for portions of the pipeline that cross public State lands. If the State refused to grant these rights-of-way, however, Northwest could still obtain the land through condemnation powers it will receive upon final FERC certification.

--Alaska Pipeline Commission: The Alaska Pipeline Commission has no jurisdiction over the tariff charged for intra-state shipments of gas in an inter-state pipeline.

--Local hire: The State's "local hire" law, implemented by the Department of Labor, is currently under review by the U.S. Supreme Court.

State public utility commissions: Public utility commissions in the United States regulate sales in which the buyer and seller are both located in that State. For example, FERC will approve the sale of gas from EXXON to a pipeline transmission company. A State PUC will then approve the sale from that transmission company to a local distribution company.

Canada

Parliament: An Agreement between the United States of

AGO 532685

America and Canada on Principles Applicable to a Northern Natural Gas Pipeline, (sometimes called the Bilateral Treaty), was approved by the Canadian Parliament last year. The treaty covers a broad range of issues, including: a construction timetable, pipeline capacity, financing, taxation, tariffs and cost allocation, and regulatory authorities.

The Canadian Parliament in April approved the Northern Pipeline Act, which sets up a single regulatory agency for planning and monitoring construction of the Canadian segments.

National Energy Board: The NEB is FERC's Canadian counterpart and will have similar responsibilities and authority.

The NEB has broad discretion in deciding on applications of public convenience and necessity for pipelines. Canadian procedures for implementing a decision on the gas pipeline appear to be less complicated than U.S. procedures. The State Department and other federal agencies advised President Carter last summer that delays related to approval by regulatory authorities are less likely to occur in Canada than in the U.S.

The NEB already has established the pipe diameter and pressure for Canadian segments of the line.

AGO 532686

III. ENGINEERING AND SCIENTIFIC CONSIDERATIONS: PIPELINE DESIGN AND FIELD ACTIVITIES

BACKGROUND

The design of the pipeline (and compressor stations) establishes thresholds for the volume of gas and its quality that may be transported through the line. The various elements of pipeline design, in turn, determine the field activities (conditioning) which must take place in preparing the gas for pipeline transport.

Questions relating to pipeline design and conditioning are based on two considerations:

1. What quality of gas is to be transported through the line; and
2. What is the volume of gas?

Resolution of these questions by the producers, State, FERC, investors and gas purchasers will require a complex balancing of economic and regulatory factors, as well as the technical characteristics of oil, gas, and transportation facilities.

A. Gas Quality

The Prudhoe Bay reservoir contains crude oil and "associated gas" in the form of "gas cap gas" (located above the crude layer) and "solution gas" (dissolved in the crude). The hydrocarbons in these gas and oil layers represent the entire spectrum.

AGO 532687

For the purposes of this report, these hydrocarbons will be referred to as "dry gas," "gas liquids," and "crude oil" as follows:

DRY GAS	GAS "LIQUIDS" (NGL's)				CRUDE OIL
C^1	C^2	C^3	C^4	C^5	C^6 and higher
methane	ethane	propane	butane	pentane	

The purpose of the Northwest pipeline is to transport those hydrocarbon components that physically cannot, or economically will not, be carried in the existing TAPS oil line. These remaining components represent dry gas and gas liquids. The first question to resolve is, "What can TAPS be expected to carry?"

1. Transport of Gas Liquids in TAPS

Note: Most of the technical interpretations cited here are extracted from SOHIO and ARCO letters to FERC dated March 9, 1978, and March 27, 1978, respectively.)

a. Physical Constraints for Transport of Liquids in TAPS

Crude oil emerging from the Prudhoe Bay reservoir is extremely hot; however, the delivery temperature of crude to the TAPS line is regulated at no greater than 140 degrees F, with a maximum

AGO 532688

"vapor pressure"[1] of 14.7 psia[2] which is equivalent to natural atmospheric pressure at sea level. At a higher temperature, or if the crude composition resulted in higher vapor pressure qualities, then the line would be threatened by the presence of two "phases" of hydrocarbons--those which flow as a liquid, and those which flow as a vapor or gas. "Two-phase flow" in either oil or gas lines results in difficult and hazardous operating conditions.

While the crude cannot be allowed to enter TAPS at a temperature of more than 140 degrees F, it has a minimum temperature limit as well. Crude must be supplied to TAPS at a high enough temperature to ensure that by the time it reaches Valdez, it will not have cooled into an immobile sludge("wax" precipitates as the temperature cools.) SOHIO reports that this lower temperature threshold for pipeline entry is about 100 degrees F, ± 10 degrees; and ARCO reported the threshold at 105 degrees F.

Presently, the crude delivered to the TAPS line is at the maximum temperature (140). Under these conditions, SOHIO believes the line can carry much of the pentanes (no butanes or lighter components).

1/ Vapor pressure for oil is the pressure at which any decrease will cause the lighter hydrocarbons to enter the gaseous phase. This vapor pressure is determined by the composition of the oil. Oil with no NGL's will have a low vapor pressure. Oil with NGL's will have a higher vapor pressure.

2/ Pressure is expressed as psi, psia or psig. The differences will be ignored for the purposes of this report.

AGO 532689

In summary, there are two competing physical factors which are considered by the producer in choosing whether and how much gas liquids to ship through the TAPS line. Reduction of crude temperature will allow more liquids to be carried; however, this means that in the event of a temporary pipeline shut-down, the risk that crude might turn into a semi-solid sludge will increase. Hence, there are very definite physical characteristics which limit the type and amount of liquids which TAPS can accommodate. It is safe to say that most pentanes could physically be put into TAPS and possibly some butanes.

b. Economic Constraints for Transport of Liquids in TAPS

Even if the maximum volume of butanes and pentanes were transported through TAPS in the crude stream, it may be a useless gesture. While TAPS can accommodate crude with a 14.7 psia vapor pressure, tanker limits are 14.0 and Los Angeles air pollution regulations set the maximum limit on crude to be stored there at 11.1. Lower vapor pressures are attained by removing the lighter liquid components. Hence, unless a butane/pentane purchaser is waiting in Valdez, these components are destined to greet the "thermal oxidizers" (otherwise known as flares). Transporting butanes and pentanes through TAPS for flaring in Valez is of questionable economic merit.

2. Transport of Gas Liquids in the Gasline

Once it is determined how much of the gas liquids TAPS can and will carry, the question turns to the physical and economic constraints of the gasline.

a. Physical Constraints for Transport of Gas Liquids in the Gasline

While oil lines (which transport hydrocarbons in a liquid state) are more comfortable transporting heavy hydrocarbons, gaslines (which transport hydrocarbons in a gaseous state) prefer the opposite end of the spectrum. ARCO maintains that under any realistic operating pressure and temperature for the proposed gasline, all the methanes (C^1), ethanes (C^2), and the propanes (C^3) can be shipped through the gasline, without fear of "condensation" (which would result in hazardous conditions of "two-phase flow"). The amount of butanes (C^4) and pentanes (C^5) which can be carried increases with the pressure of the line. For example, a 2160 psi gasline could carry everything--all the butanes and pentanes. However, technological concerns arise at this high pressure, as the highest pressure in which a pipeline has operated to date (for gas compositions and line diameters similar to those anticipated for the Alcan line) is about 1000 psi. 1260 is a more realistic assumption for the proposed Northwest line. ARCO projects that a 1260 psi line can carry about 25-60% of the butanes and none of the pentanes.

b. Economic Constraints for Transport of Gas Liquids in the Gasline

When negotiating sales contracts for methane gas, the producers and purchasers will determine whether it is in their respective interests to include liquid portions of the gas stream in the sale agreements--at least those liquids which physically can be transported through the gasline. Considerations

AGO 532691

will include marketability of liquids in the lower states, purchaser's downstream interests and the producer's alternatives for field operations fuels. While it is true that a molecule of ethane or propane has a higher heating value, expressed in British Thermal Units (BTU's) than a molecule of methane[1], it may or may not be of greater economic value as part of the gas stream or sold separately as petrochemical feedstock. Joe Moore of Bonner & Moore provided the following ball-park estimates of BTU values during conversations with the Feminist Oil Caucus:

C_2^1	(methane)	- 950 BTU's/MCF
C_2^2	(ethane)	- 1700 BTU's/MCF
C^3	(propane)	- 2100 BTU's/MCF

"Enriching" the methane gas stream by inclusion of these heavier hydrocarbons may impose downstream processing costs if the gas is destined for commercial or residential use. This is because distribution lines operate at low pressures and physically cannot carry heavier hydrocarbons without risking "two-phase flow" problems. Hence, propane and butane would need to be removed. Conceivably, ethane could remain in the stream (provided it had no higher value in an alternative use), and the gas company would simply inject useless inert gas to bring the BTU content down to minimum standards thereby

1/ Ethane (C^2) and propane (C^3) have more carbons (per cubic foot of volume) available for oxidation (burning) than does methane (C^1); hence, greater heating value.

AGO 532692

increasing the volume (MCF's) available for sale.

In summary there appears to be little debate that TAPS can physically carry all the pentanes (C^5) and heavier hydrocarbons; and that the gasline will be capable of shipping about half of the butanes (C^4). Subjecting this to possible economic considerations, it appears that at most half of the butanes and some or all of the pentanes(+) might have difficulty finding a way south under realistic operating conditions of both TAPS and the proposed gasline. Further, producers have maintained that these stranded hydrocarbons can all be used on the North Slope to fuel field operations.

WHAT ARE WE TO DO WITH HALF THE BUTANES & ALL THE PENTANES?

3. Other Quality Considerations for the Gasline

In addition to the hydrocarbon components, Prudhoe gas contains several impurities. The most important impurities are carbon dioxide (CO2) and water (H2O).

a. Carbon Dioxide Considerations - Produced gas volumes are expected to contain roughly 12% CO2. There are several considerations which will determine how much of this CO2 is removed from the gas stream in the field.

Reasons to remove the CO2:

(1) CO2 has no BTU value, so shipment through the pipeline means that fuel will be used to move it and its presence reduces the amount of hydrocarbons that can be shipped each day.

(2) CO2 is corrosive if it combines with water, forming carbonic acid.

Reasons to not remove CO2:

(1) CO2 is a key ingredient in the manufacture of methanol and ethanol and might have some value for sale along the pipeline route.

(2) CO2 might be injected into Alberta oil fields to increase production, or it might be used as an atmospheric additive to greenhouses. (Greenhouses may be constructed to utilize waste heat near the compressor stations.)

(3) CO2 affects the dewpoint of the gas: a high CO2 content means that line pressure must fall to a lower level before liquids condense--hence, CO2 in the line means that heavier hydrocarbons can be carried.

b. Water Considerations - Water has no beneficial qualities to lend to the gas stream. The question is, rather, how much money should be invested to dehydrate the gas stream so that water problems can be minimized. Excessive amounts of water can cause two problems:

(1) Corrosion - If water mixes with CO2, carbonic acid may form.

(2) Condensation - As the concentration of H2O is increased in a pressurized gasline, droplets may form causing dangerous "two-phase flow" problems.

In summary, determining how much of the CO2 and H2O to remove from the gas stream is a matter of judgment and will require the balancing of physical, economic and regulatory considerations.

B. Volume of Gas

The amount of gas available for shipment through the gas pipeline will depend on several factors, the most important of which are the production rate of gas fields supplying the

AGO 532694

line and the amount of gas sold for shipment.

1. Production Rate

The President's Decision based its economic projections on a gas delivery rate to the pipeline of 2.4 billion cf/d from North Slope fields and 1.5 billion cf/d from Canadian fields. These assumptions need not be the basis by which FERC certifies pipeline capacity, and it is inevitable FERC will face difficult decisions in making the final capacity determination. The 1.5 billion figure for Canadian gas is totally speculative, since no one can predict when MacKenzie Delta production will be authorized and a spur delivery line constructed. The validity of the 2.4 figure has been questioned on several grounds:

(a) The approved operating plan for the Prudhoe Unit calls for offtake of 2.7 bcf/d of raw gas which would yield about 2.0 bcf/d of pipeline quality gas from the Sadlerochit reservoir. While that is the approved plan, it could be changed in the future if Prudhoe production characteristics prove different from today's expectations. The State's Oil & Gas Conservation Committee is charged to ensure that production is not wasteful of hydrocarbon resources.

(b) Dr. Todd Doscher, a legislative consultant and professor of petroleum geology at the University of Southern California, told a congressional committee last year approval of the gas pipeline should be delayed for three years until there has been time to assess reservoir performance. He stressed the importance of not committing the capital to construct the pipeline until there is absolute certainty the gas can be withdrawn without affecting ultimate oil recovery. Nevertheless, Congress gave the go-ahead to the Alcan project.

(c) The Kuparuk and Lisburne pools might supply additional volumes, but the producers have specified no plans for bringing these areas into production.

These problems and uncertainties will have a negative influence on investor interest in the gasline--particularly if the general economics are marginal.

2. Gas Sales

Produced gas will not be shipped through the pipeline unless it is sold by the gas owners (producers and the State) to purchasers who choose to use the line. The producers cannot be forced to sell their gas, and the purchasers cannot be forced to use the line. Presumably, if the gas is sold to the pipeline owners, those volumes will be shipped through the proposed gasline. However, if a purchaser secures the gas for use on the North Slope or upstream from the pipeline's Lower 48 outlets, then downstream capacity may be left unused, unless supplemental sources are found. Additionally, the spectre of using LNG tankers to transport the gas from the North Slope to markets has been raised.

In summary, FERC will certify that the pipeline be designed to carry an expected capacity, but determination of this "expected" capacity will be difficult.

PIPELINE DESIGN

The three major components of pipeline design are (1) volume capacity or "throughput," (2) quality specifications and (3) placement above or below ground. The background information relating to these factors was discussed in the previous pages.

AGO 532696

A. Volume Capacity

The volume (measured in MCF's - thousand cubic feet) shipped through the gasline each day will be dependent upon "deliverability," which includes both the volume produced and the volume made available for shipment by the gas purchaser. The volume also will be affected by the pipeline design which controls how much the pipeline physically can carry. Presumably, these physical constraints of pipeline design are based on expectations for deliverability.

In viewing how pipeline design and volume capacity interrelate, another complicating factor enters the picture. The volume of gas shipped through the line each day is dependent upon three factors of pipeline design: pipe diameter, inlet gas pressure and "pressure drop." A range of diameter and pressure specifications[1] will be capable of carrying the same volume of gas throughput. As the diameter is increased, the pressure capabilities can be reduced. Hence, a 48-inch diameter line must operate at a higher pressure than a 56-inch line carrying the same volume of gas. Selection of pipe diameter and pressure will include consideration of differences in capital costs, variations in fuel efficiency for operations, and safety factors, in addition to consideration of how much gas will be available for shipment.

FERC is responsible for establishing the final pipeline capacity for the U.S. segments of the gasline; the National

1/ In general, the pressure specifications of a pipe are determined by the thickness of its walls and choice of steel.

AGO 532697

Energy Board (NEB) is responsible for the Canadian portions. In so doing, these agencies must balance the need to ensure financibility (which requires that capacity is viewed conservatively, judging economic viability from committed rather than expected volumes) and the need to design a line which can accommodate future volume additions (which is a federal concern in that it relates to maximizing the availability of domestic energy resources). This latter concern for accommodating future volumes is important, because while the pipeline diameter and thickness of its walls, along with the capabilities of compressor stations, allow for some flexibility in throughput levels, it costs a tremendous amount to install additional compressors or to "loop" the line by laying a new line right next to the original.

The history of Alcan's proposal before the FPC (now FERC) last year demonstrates these competing concerns. Its initial application was for a 42-inch line in Alaska to carry 2.0 bcf/d. However, following the unfavorable decision in March by Judge Litt, Alcan amended its application to 48 inches, 2.4 bcf/d, like the competing Arctic proposal.

FERC has not yet established the volume capacity specifications for the United States segments; however, the NEB has done so for the Canadian portions. In February of this year, it determined that the line would be 56 inches with walls thick enough to operate at 1080 psi, based on an estimated throughput of 3.6 bcf/d (2.4 from Alaska and 1.2 from the as-yet undeveloped

AGO 532698

MacKenzie Delta). The Canadian decision was influenced by the fact that only one of Canada's two pipe mills could produce 48-inch pipe, while both could roll 54-inch or 56-inch pipe.

While the NEB decision does affect FERC's choices for U.S. pipeline design capacity, a variety of diameters and pressures can be built in Alaska to transport 2.4 bcf/d to Canada. Furthermore, one can expect that throughput specifications will continue to be examined by FERC since the NEB decision can be changed prior to final certification by both countries, and the Canadian-U.S. "Bilateral Agreement" specifically mandates cooperation between these two regulatory bodies.

B. Quality Specifications

Based on the line operating pressures and risk and safety considerations, FERC will establish quality standards for gas offered for shipment. Specifications may include:

(1) dewpoint - specifying the maximum BTU level and the amount of heavy hydrocarbons allowable.

(2) impurities - specifying the maximum amount of CO2 and H20 that may remain after conditioning of the raw gas.

(3) temperature - specifying the required temperature of the gas stream (as it must be chilled to prevent problems in areas where the line is buried in permafrost).

(4) pressure - specifying the required compression necessary.

C. Placement Above or Below Ground

Under normal environmental conditions of the United States, the best way to lay pipe for gas shipment is to bury it in the ground. However, Arctic and sub-Arctic conditions present

AGD 532699

unique problems. In permafrost areas, hazards posed by frost heave and differential melting raise technological questions as to the feasibility of burying the pipe--even if gas is chilled below freezing before it enters the pipe. If risks are substantial, FERC might require those sections of the line to be elevated above ground level like much of the TAPS oil line. A significant amount of elevated pipe would substantially increase the cost of the line and exacerbate security problems which could pose even greater hazards than the elevated TAPS oil line.

FIELD ACTIVITIES

(including gathering, conditioning, and water injection)

Those activities which will take place prior to shipment of gas in the pipeline will be determined by the pipeline design. These activities include:

(1) gathering - which is the transportation of gas from the numerous wells in the field to the conditioning facilities and to the gas-line, by means of non-regulated, producer-owned gathering lines.

(2) conditioning[1] - which includes a variety of processes for turning the raw gas into "marketable quality" and further into "pipeline quality" (dewpoint, impurities, temperature, pressure).

1/ "Processing" has sometimes been used interchangeably with the word "conditioning." However, it has also been used to describe the dewpoint portions of conditioning activities; or it is used to denote the downstream extraction of gas liquids and upgrading into petrochemicals. Due to these ambiguities in meaning, the word "processing" will be avoided here.

AGO 532700

(3) water injection - Though not a part of gas conditioning itself, the production of the gas cap and subsequent sales probably will require that a water injection facility is built to restore pressure to the field necessary for optimum oil production.

FERC will determine who will be responsible for raising the capital for field gathering, conditioning and water injection facilities. Those facilities which FERC attributes to gas "production" must be built by the producers (and will not be regulated by FERC). Those facilities which FERC allocates to gas "transportation" must be built by the pipeline owners (and will be regulated by FERC and included in the pipeline tariff). In making this decision, FERC must consider not only the basic arguments of what constitutes production and processing of raw gas into a marketable product and what constitutes upgrading of the marketable product into a transportable product, but it must also consider several policy questions, including the following:

(1) EIS - The Alcan environmental impact statement did not examine the impacts of the upstream facilities for conditioning. If any of these facilities are subsequently deemed to be part of the pipeline, then the existing EIS may be inadequate.

(2) Non-owner access to the conditioning plant - If the producers must build the conditioning plant, then it is not subject to FERC's jurisdiction. Questions have been raised as to whether this might necessitate the duplication of conditioning facilities by non-Unit leaseholders and future Beaufort leaseholders on the North Slope.

(3) Overall project viability - The Northwest project can move forward only if the producers are willing to sell their gas and if the investment community is willing to furnish debt capital for the pipeline.

AGO 532701

Producers argue that if they must build conditioning facilities, they might decide the investment at this time is not worth the gains to be made from gas sales. On the other hand, Northwest argues that if the total capital required for pipeline construction increases due to inflationary delays or other reasons, then they might not be able to raise sufficient debt. These problems are discussed in more detail in the pricing and financing sections of this report.

IV ECONOMIC CONSIDERATIONS: PIPELINE FINANCING, GAS PRICING, AND TARIFFS

Whether the Alcan line is a sound investment will be influenced by the ultimate market value of the gas. This market value is determined not only by the economics of the free market, but also by government regulation of pricing and tariffs. Expectations of the ultimate market value will determine (a) whether the gas is sold, and (b) whether the pipeline is financed.

It is difficult to determine with any certainty how much the free market would pay for Alaska gas. There are uncertainties within the free market itself (the price of alternative crude-based fuels in 1990, for example) and uncertainties about what course the federal government will take in regulating gas and other energy prices.

Domestic production of natural gas began declining in 1972. There has been a growing shortage of gas since 1971, and the shortage reached serious levels in the winters of 1975-76 and 1976-77.

The direct cause of this shortage was price regulation by the Federal Power Commission (FPC). By maintaining an artificially low price, the FPC made natural gas the choice fuel. The demand for gas has grown at an annual rate of 5.3 percent since 1970. At the same time, low prices depressed supplies by removing incentives for exploration. Total U.S. gas reserves

AGO 532703

fell by about a third between 1967 and 1976.

Under the Natural Gas Act of 1938, the FPC was authorized to regulate the transportation charges of the interstate pipeline companies. As prices paid by consumers began increasing, pressure was brought on the FPC to extend controls to wellhead prices. The FPC refused to extend its jurisdiction until 1954, when the Supreme Court ordered it to regulate the price of gas sold to interstate pipelines (Phillips Decision).

Prices were held at very low levels through the 1960s. The average new contract price was only 19.8 cents per mcf in 1969. The FPC allowed prices to rise somewhat in the early and mid-1970s in response to shortages, and new contract prices averaged 60 cents in 1975. The price of gas was still far below its free market level. The world price of energy in 1975 was about $12 per barrel, but 60-cent gas is equivalent to oil at $3.50 a barrel.

In June, 1976, the FPC issued Opinion 770, a decision that set the national area rate for new contracts at $1.42 per mcf, with future price increases of 4 cents per year. This decision was challenged and upheld in the courts. The new contract price in 1977 averaged about $1.46 per mcf, which is equivalent to oil at about $8.50 per barrel, well below the world market price.[1]

1/ Information and statistics in this section are taken from the book, Options for U.S. Energy Policy, by the Institute for Contemporary Studies, 1977; specifically from the chapter, "Prices and Shortages: Policy Options for the Natural Gas Industry," by Robert Pindyck.

Looking to the future, it is not clear which direction federal policy will take. On one hand, some argue that the federal government should reduce its role as a regulator and allow the free market to operate. However, others argue that the federal government should continue its historic role in regulating gas prices.

Market value is basically the price the consumer is willing to pay (assuming he has a choice). This is influenced by two factors: (1) What are his alternatives (including other fuels and other gas sources)? and (2) What actions has government taken to subsidize certain energy supplies through devices such as rolled-in pricing (averaging high-cost supplies with low-cost supplies)?

The producer must then determine whether the price the consumer is willing to pay is high enough to meet his perceived value of the gas at the wellhead and the cost of transporting it to market. In a strictly free market system, the wellhead value is what the consumer is willing to pay, less the cost of transportation to market. However, in our regulated system, government restricts selling price through imposition of a wellhead ceiling. In the case of Alaska where transportation costs are extremely high, the wellhead value may be below the ceiling, and therefore the ceiling would not function. For example, the North Slope oil producers receive an average of between $5.00 and $8.00 per barrel for their oil despite a federal ceiling of more than $11.00.

AGO 532705

If the consumer determines the gas will cost him more than he is willing to pay (market value), or if the producers determine that the wellhead value is unreasonably low and better options may exist in the future, then gas sale contracts may not materialize. In the event these gas sale contracts do not materialize for economic reasons, the government might choose to use its regulatory powers to enhance the saleability of Alaska gas if the importance of a secure domestic source outweighs other considerations. For example, rolling-in the high-priced Alaska gas with lower-priced gas from regulated domestic sources would make the Alaska gas cheaper, and therefore more attractive. The government also will have the power to encourage or limit the availability of other alternative gas supplies like SNG, LNG imports and Canadian and Mexican gas.

In spite of all government actions to manipulate the free market through regulation and facilitate the consummation of gas contracts, the gasline will not be built unless the financial community believes it is a worthy investment.

The financial community normally decides whether to invest in a project based on its economic viability. In the case of the Alcan line, viability may hinge on government manipulation of the free market system. Even though the purchaser (generally a Lower 48 utility) may be willing to pay a "rolled-in" price for Alaska gas, the financial lenders and investors can be expected to take a more conservative approach if the project is not viable on its own economic merits. The scale and uniqueness of

the project, the large amount of money involved, and the technical, marketing and regulatory uncertainties further increase the risk for investors.

If the financial community believes the project is not viable in a traditional economic sense, it still might be willing to invest if the federal (or State) government agreed to provide the ultimate financial backstopping to assure debt recovery.

Congress and President Carter, however, have explicitly ruled out federal financial participation and have relied on assurances from Northwest that the project can be "privately" financed. The federal government believes its financial participation in the project is unwise for a number of reasons, and therefore, a reversal of the federal stance is unlikely until Northwest has exhausted all avenues--and failed.

The President's Decision

Private financing: President Carter's "Decision on the Alaska Natural Gas Transportation System," which was approved by Congress last fall, states that the pipeline must be privately financed. Privately financed in this sense means non-federally financed. It does not exclude state participation. The Decision explicitly rejects federal participation and states that consumers will not share any risk prior to completion of the pipeline. The Decision specifies that producers of Alaska natural gas may provide guarantees for project debt but may not own any portion of the pipeline, which would result from

contribution of equity capital. The prohibition against equity participation by the producers was based on anti-trust complications raised by the Justice Department.

A report to Congress accompanying the Decision says the "direct beneficiaries" of the project have sufficient credit support capacity to assure completion of the pipeline without assistance from consumers. Such direct beneficiaries, the report says, are the gas transmission companies, gas producers and the State of Alaska.

Cost: The President's report to Congress says the pipeline is expected to cost about $10.3 billion, adjusted to reflect commencement of operations on January 1, 1983. With a 32% overrun, total capital requirements would rise to about $13.6 billion, the report says. The Alaska section of the line is projected to cost $3.7 billion, not including expected overruns. A 32% overrun would add about $1 billion to the cost of the Alaska segment. (These figures include a one and one-quarter year lag in outlays and a 5% inflation factor.)

The report sets out a four-part plan to effectuate private financing and balance the project's risks and benefits:

1. Equity investment is to be placed at risk under all circumstances, and the budgeted equity investment is to be considered the first money spent. The rate of return on equity will compensate sponsors for bearing this risk.

2. Producers and the State of Alaska, as direct and major beneficiaries of this project, should participate in the financing either directly or in the form of debt guarantees.

AGO 532708

3. The burden of cost overruns is to be shared by equity holders and consumers upon completion through the application of a tariff based on a variable rate of return on common equity.[1] This would provide a strong incentive for the project to be constructed at the lowest possible cost.

4. Provision of debt service in the event of service interruption would be borne by consumers through a tariff that becomes effective only after service commences, sometimes called a "minimum bill" tariff.

Marketability and Economics

The President's Report to Congress says the pipeline project is economically sound and that even in the event of extreme cost overruns, the delivered cost of Alaska gas will be economically attractive. The conclusion that Alcan can be privately financed is founded on the basic economic desirability of Alaska gas and the viability of the Alcan transportation system; nevertheless, "skillful financial packaging and risk-benefit balancing will be required," the report says.

However, three legislative consultants have challenged the assertion that the Alcan project is economically viable.

Consultant Joe Moore of Bonner & Moore told the House Special Committee on Royalty Oil and Gas April 5th that Alaska gas delivered through Alcan will not be able to compete in the

1/ On May 8, 1978, FERC published a "Notice of Proposed Rulemaking" seeking comments on proposed ways to structure the variable rate of return. Comments are due June 14th.

Lower 48 unless the government "circumvents and manipulates" the free market through rolled-in pricing. Moore estimated Alaska gas will cost about $5 per million btu's (mmbtu) at the end of the Alcan line, assuming Alcan and downstream distribution tariffs of $3.50 and a wellhead price and conditioning charge of $1.50. This is twice as high as the comparative cost of crude oil at $2.50 per million btus, Moore said. Consumers will not buy Alaska gas unless its high price is averaged in with the lower-priced, regulated gas produced in the Lower 48.

Consultant Todd Doscher, who worked as a consulting petroleum engineer for Shell Oil for 25 years before becoming a university professor and consultant, told the House Special Committee on Royalty Oil and Gas April 14th it is unlikely Alaska's gas will be competitive in the Lower 48 markets in the near future. Doscher released to the committee a report that he and about 35 other geologists and engineers prepared for the Department of Energy during the last year. The report shows there is a possibility that in the next 20 years 200 trillion cubic feet of unconventional natural gas could be recovered from the Tight Sands of the Rocky Mountains at a price of less than $3 per mcf. Half of that amount, 100 trillion cubic feet, could be recovered at a price of $1.75 per mcf, he said. This study will be validated in two to three years, and if it proves to be true, this would be a large, competitive source that would undercut the marketability of Alaska gas, Doscher said.

"I think you have to check on this matter before you go

committing your money to the pipeline that just may possibly sit idle for 10 or 15 years until this gas supply from unconventional sources is used up," he said. Even if the Alcan line could be built for $10 billion, the lowest amount anyone is predicting, the delivery cost to market will be in the range of $2 to $3 per mcf, he said. This would mean a city-gate cost in the range of $4 to $5 per mcf, including the wellhead value and conditioning. This price will not be competitive, he said.

In addition, Doscher said he believes that a price of $3 per mcf would stimulate production of 25 to 100 trillion cubic feet of gas from conventional sources.

From now until the year 2000, Doscher said, it is likely that gas can be supplied for less than $3 per mcf with the possible exception of California markets.

Consultant Arlon Tussing also has questioned some of the federal government's basic assumptions relating to the project's economic viability and the probability of private financing.

In general, Tussing says, natural gas is worth the price of its nearest substitute (number two fuel oil). Consumers generally will pay anything up to that price, but not much more. The supplementary gas projects now under consideration--such as SNG, coal gasification, LNG imports and Alaska gas--are expected to cost about $4 to $6 per million BTU's (1977 dollars).

AGO 532711

It is widely assumed by leaders in government and industry that the world supply of oil will tighten by the mid-1980s and that the real price of oil will rise throughout the late 1980s and 1990s. It is further assumed that coal gasification, LNG projects, and pipelines from the Arctic do not have to meet the test of today's oil prices, but make sense even if they cannot deliver energy except at considerably higher real costs. Although this outlook may be the most probable one and the most prudent basis for public policy, Tussing says, there are other plausible scenarios in which the real price of oil will not rise and might even fall. What is the correct forecast is beside the point: there remain genuine uncertainty and serious controversy over the future course of oil prices, and they will (and should) influence the attitudes of institutional lenders toward the creditworthiness of major gas supply contracts, Tussing says.

It has also been argued and assumed that rolled-in pricing will assure the marketability of Alaska natural gas, even if it is more costly than alternative energy sources in the mid-1980s. It is true that gas transmission companies and distributors are now contracting to pay up to $5 per mmbtu for supplemental gas supplies. Regulated gas companies are willing to pay more for supplemental gas only because the expensive supplements can be rolled together with the price of domestic "old" and "new" gas, whose regulated prices are considerably lower than their market value, Tussing says.

The marketability of Alaska gas requires an adequate margin of low-priced gas through the 1980s to subsidize transportation of gas from Alaska. While a reasonable case can be made that the margin will be adequate, there are other plausible scenarios in which little or no margin will be left for rolled-in pricing to assure the marketability of gas that enters Lower 48 distribution systems after 1981.

Deregulation of new gas, for example, would allow gas distributors to bid up the price of new gas supplies to levels at which the average price of all gas approximates its market value. Even without deregulation, Tussing says, the growing portion of higher-priced "new" gas, Canadian and Mexican pipeline imports and other more costly supplemental supplies could well wipe out the margin between the average price of gas under existing contracts and the price at which gas can be sold, as soon as the early 1980s.

Regardless, Tussing says, lenders are not going to know what will happen to the regulatory system or to the price composition of U.S. gas supplies over the economic life of the Alcan pipeline, and they will not finance any system whose viability depends both upon a continuation of price controls on conventional natural gas and upon a relatively slow movement of higher cost unconventional supplies into the distribution system.

Tussing believes that regardless of the decisions Congress and FERC make about natural gas pricing, including the pricing and rolling-in of Alaska gas, lenders will require the Alcan project to be viable under the assumption that it would be

competitive on an incremental price basis. If the Alcan pipeline is to be financed by conventional private means, Tussing says, the average cost in constant dollars of that gas, delivered to its final consumers, cannot be higher than the price of No. 2 distillate oil on the world market. Moreover, lenders must be very confident that capital cost overruns, delays and production problems will not be severe enough to run the delivered cost of the gas so far above the expected value that it is unmarketable.

There is no way lenders can be given such an assurance, Tussing says. The maximum market value of natural gas is now no more than $2.60 to $3.00 per mmbtu. Assuming the higher figure, a wellhead price of $1.48 (congressional compromise) together with the estimated Alcan tariff of $1.04 (President's report) would leave only 51 cents for gas conditioning, transmission beyond the tailgate of the Alcan system, storage and distribution.

Therefore, there are wholly plausible assumptions under which the Alcan system might not deliver marketable gas and would not meet a conventional cost-benefit test, and in which its net national economic benefit, conventionally measured, would be zero or negative, Tussing says. However, he says this does not imply that some other system should be approved for transmission of North Slope gas, or that no system should be built. The immediately relevant and pressing conclusion, however, is that the prospects for purely private financing are actually quite slim.

Attitude of North Slope producers concerning financial participation:

Despite President Carter's invitation to the North Slope producers to share a portion of the debt for the project, it appears highly unlikely any of them will do so. (The President's Decision prohibits equity participation by the producers.)

Claude Goldsmith, Vice President of ARCO, told a congressional committee last fall his company does not intend to help pay for Alcan: "Aside from the possibility of anti-trust legislation and the political climate regarding divestiture, the economic attractiveness of investment in an Alaskan transmission facility has been severely dampened for Atlantic Richfield, and, presumably, for the investment and banking community, by the recent proceedings fixing tariffs on the trans-Alaska oil pipeline. The Interstate Commerce Commission there reversed, without hearing, a methodology for computing pipeline tariffs which had been commonly employed and accepted for 35 years. Under these circumstances, Atlantic Richfield is currently of the opinion that its financial participation in a gas pipeline system for transportation of Alaskan gas would be ill-advised."

Under the proper circumstances, Goldsmith said, ARCO would not be opposed to financing a portion of the gas conditioning plant. However, a prerequisite to such investment would be the fair and non-discriminatory treatment of Alaskan producers as to wellhead gas price and a return on gas conditioning plant investment comparable to that which will be received by the owners of the gas transmission system. ARCO's participation also is

AGO 532715

conditioned upon investment by others in the venture.

Business Week recently (April 10, 1978) quoted SOHIO ex-chairman Charles Spahr on the possibility that SOHIO will invest in the gas line: "SOHIO is unable to undertake such a risk even if it wanted to do so, which it certainly does not."

Pricing Methods

In setting a wellhead price for gas, the FPC traditionally used a "cost-based" method, which is based on the producers' costs in developing and producing gas from the field.

Cost-based pricing is somewhat arbitrary when it is applied to gas that is produced in association with oil (associated gas), because it is impossible to determine precisely the costs of finding, developing and producing only the gas. Therefore, the FPC in recent years has set the price for gas based on the cost of producing only non-associated gas (gas not produced in association with oil), and then has allowed the same price to be paid for associated gas produced in that area.

Alaska gas is produced in association with oil. Therefore, if FERC were to set the price for Alaska gas under the Natural Gas Act, complex and lengthy hearings would be required to allocate costs between oil and gas production, a procedure which has not been attempted since the mid-1960s. The President's Decision says that procedure likely would take more than 18 months.

The President's Decision urges that Congress adopt a "commodity-value" pricing method for North Slope gas as set forth in the administration's proposed National Energy Act, which

still is stalled in a House-Senate conference committee.[1] The National Energy Act would amend the Natural Gas Act and set the rate for Alaska gas at $1.48 per mmbtu, subject to annual escalation equal to inflation.

If Congress fails to adopt the National Energy Act or some substitute for it, FERC will set the price for Alaska gas under the Natural Gas Act of 1938.

The "commodity-value" approach proposed by Carter apparently would calculate the wellhead or netback price by subtracting the cost of transportation from the value of the gas at the city gate, as determined from the cost of alternative fuels. Netback pricing is intended to assure the marketability of the gas, although it would be workable only if the expected netback price were high enough to cover field development, transportation and gas processing costs. The President's report is vague on how this method would actually work.

The President's report estimates that the wholesale or "city gate" price for North Slope gas will be about $2.50 to $2.80 per mmbtu (in constant 1975 dollars), assuming a 40% cost overrun in building Alcan. It should be noted that this represents the average tariff over the 20-year life of the line. However, the initial tariff during the early years will be higher,

1/ As of June 2, a congressional House-Senate Conference Committee had reached agreement in principle on major items and policy relating to natural gas pricing, which is one section of the five-part National Energy Act. The conference committee has yet to resolve more than 30 "technical" items. After agreement is reached on all items, from four to six weeks will be needed to draft the agreement into bill form. Most observers predict Congress will not take final action on the natural gas compromise until August or September.

thus further impeding marketability.

The report projects the delivered cost of Alcan gas under three different overrun assumptions:

20-Year Average Alcan Delivered Cost
(1975 dollars)

	Field Costs	Expected 40% Cost Overrun	Worst Case Cost Overrun
Field Price	$1.45	$1.45	$1.45
Processing	0 to .30	0 to .30	0 to .30
Transportation (Alcan tariff)	.80	1.04	1.57
Delivered Cost:	2.25 to 2.55	2.49 to 2.79	3.02 to 3.32

(These calculations are based on a throughput volume of 2.0 to 2.5 billion cubic feet per day.)

The President's report says conservatively projected costs of imported LNG and other alternative non-conventional gas supplies would be at least $3.25 per mmbtu (in 1975 dollars). SNG would be at least $3.75 per mmbtu. Only if there were a "worst case" cost overrun and high processing costs would Alaska gas be more expensive than imported LNG; it would still be considerably less expensive than SNG.

Therefore, the report concludes, the Alcan project would appear to be competitive for the life of the project.

The $1.04 tariff assumed in the President's report is a 20-year average over the life of the project. John McMillian, Chairman and Chief Executive Officer of Northwest Alaskan, said at a Juneau press conference April 15th that the tariff in the early years of the project is now expected to be about $2.22.

AGO 532718

A tariff of more than $2 could mean a city-gate price of more than $5: $1.45 wellhead value + 75 cents gathering/conditioning + $2.22 tariff + 75 cents storage and distribution charges = $5.17.[1]

Elements that affect the value of Alaska gas: A number of variables and unresolved matters make it almost impossible to determine, at this point in time, the value of Alaska gas, or the amount of money the producers and the State will receive from sales of the gas. It is for this reason the North Slope producers have been unwilling to negotiate sales contracts.

Gas "commitments" were negotiated between the producers and gas purchasers several years ago in order for the pruducers to obtain front-end capital (advance payments) to assist their pipeline and field development. These "commitments" were not specific on price and have since been invalidated.

Wellhead price ceiling: The wellhead ceiling (assuming one is established by Congress) will not necessarily be the price the producers will receive from sale of the gas. If the transportation and processing costs exceed the purchasers' expectations of the value of the gas when it is delivered to the city gate, then it is possible the producers will only be able to negotiate sales contracts which offer less than the ceiling

1/ These (and any) dollar figures used in projecting tariffs must be taken at face value until it is specified which reference year is used. For example, $1.04 is probably referenced to the value in 1975 dollars since that was when FPC developed the estimate; whereas $2.22 may represent dollars inflated to the start-up year of 1983.

AGO 532719

price.

It has not yet been determined by Congress or FERC whether gathering and conditioning costs can be charged to gas purchasers on top of the wellhead ceiling price, if, indeed, any purchaser would be willing to sign a contract at that price.

The latest version of the compromise energy legislation pending in Congress (as of June 2) would extend FERC's current authority to determine whether costs of compression, gathering and processing should be included in or added onto the ceiling price.

Consultant Joe Moore told the House Special Royalty Oil and Gas Committee that the North Slope producers probably will be very happy if the ultimate price they receive is $1 per mmbtu. This is because regardless of government-established price ceilings, the market value may be less. If this is the case, not only will the ceiling price become a moot question but producers may lose all interest in selling any gas at this time.

Gathering and conditioning costs: Estimates of gathering and conditioning costs vary widely. The President's report indicates that processing costs which may be assignable to gas are in the range of 0 cents to 30 cents per mcf.

FERC, in published comments on the President's report, says: "In the absence of definitive gas purchase contracts, uncertainties still remain as to whether the purchasers will have any obligations for the gas gathering and processing costs. Uncertainties also remain as to the handling of revenues

AGO 532720

attributable to the extracted liquids. Furthermore, it is still unclear whether the gas purchase contracts would provide additional gas-processing rights after the gas leaves the North Slope of Alaska. The gas purchase contracts to be negotiated between the producers and gas purchasers should address these issues."

Joe Moore told Representative Miles' committee that gathering and conditioning costs have been quoted by the North Slope producers ranging as high as $1.30 per mmbtu. Moore said he thinks it is reasonable to assume the costs will not be less than 50 cents, probably around 75 cents.[1] These costs are much higher than those assumed in the President's report.

Water injection: If gas is sold and not reinjected into the reservoir, injection of water from an extraneous body, in addition to reinjecting water produced from the field, may be required. The producers estimate these large-scale extraneous water injection facilities will cost more than $1 billion.

The Prudhoe Bay operating plan approved by the State contemplates that water injection from sources outside the pool will be instituted before production of gas for sale, although it does not require it.

FERC's comments do not resolve anything: "We are unable at this time to describe precisely how the costs of water-injection

1/ One problem in comparing conditioning cost estimates is that the processes included within that term may differ among parties making the estimates.

facilities should be balanced against the costs of gas-processing facilities, but some consideration is required. This view is expressed, however, in the context of not yet knowing the final course of reservoir management, the extent of the facilities required to implement the required operations, and the provisions of the purchase gas contracts."

Rolled-in versus incremental pricing: Northwest Alaskan officials have argued that rolled-in pricing of Alaska gas is "essential to ensuring the marketability of Alaskan gas and creating a positive atmosphere for achieving private financing for the system." Failure to mandate rolled-in pricing of Alaska gas will cause unreasonable delays and create an unfavorable market climate for the entire industry, Northwest officials have said.

Under rolled-in pricing, high-cost gas is averaged into the price of low-cost, regulated gas. Incremental pricing means the purchaser pays the full cost of the gas.

The latest version of the pending energy compromise would provide rolled-in pricing for the $1.48 wellhead and costs of transportation. However, certain charges that are permitted to be added to the wellhead ceiling price (increases in state severance taxes and costs of gathering/conditioning in excess of the wellhead) would be passed through on an incremental basis to industrial and other low-priority users.

Deregulation: The pending compromise provides for a phased deregulation of new gas prices, with all controls lifted in

1985. At the time President Carter's Decision and report to Congress was issued last September, the administration opposed deregulation: "If....proposals to deregulate natural gas prevail, serious uncertainties and delays concerning the development of any Alaskan natural gas transportation project could result." Carter now supports a deregulation compromise.

The effect of deregulation (if enacted) on the financial viability of the Alcan project appears to be detrimental, since deregulation and higher prices for domestic gas supplies will decrease the "margin" for rolling-in high-cost Alaska gas.

Tariff: Tariffs are the instruments through which the gas pipeline owners recover costs of service and a return on their total investment. It is the adequacy of this mechanism tempered by expectations of financial risks that private lenders will examine in deciding whether to lend money, since it is through the tariff that the owners obtain the funds to service debt and interest payments. Final approval of the forms of the tariffs rests with FERC.

The President's Decision says an "all-events" tariff, in which consumers guarantee at least the repayment of debt capital and interest (and possibly equity) in the event the project is not completed, is unnecessary and unwise. Instead, the President's plan recommends that FERC consider a tariff structure where consumers would pay debt service in the event of gas-flow interruptions only after the project is completed and initial operations of the delivery system have commenced ("minimum-bill" tariff).

Types of tariffs	Payment in the event of pipeline non-completion	Payment in the event of completion and subsequent gas-flow interruption
"all events"	consumers repay debt and possibly equity	consumers pay debt and equity depreciation charges
"minimum bill"	no payment	consumers pay only debt depreciation charges

The President's Decision also requires that the tariff include a variable rate of return as an incentive device to control cost overruns: the lower the cost overrun, the higher the return to the equity holder. This concept is untried in regulatory practice and the details must be worked out by FERC. The President's report suggests this variable rate of return on equity should be as high as 15%, rather than the more normal 12.5% to 14% found in recent FPC decisions. The impetus for this decision is the TAPS line. It is argued that since Alyeska knew it could recover all expenditures in its tariff, it had little incentive to minimize overruns.

Leveling the tariff: The President's report discusses the possibility of "leveling" the tariff. Normally, the cost of service (which generally includes depreciation charges and operating costs) decreases steadily over time, notwithstanding inflation. This is because as investment is depreciated and debt is repaid, both the interest charges and the rate base against

AGO 532724

which the owners are permitted to earn profits (a "return") diminish. Therefore, most tariffs are designed so that initial tariff charges are higher in the early years than in the later years.

A "levelized" tariff, in which the tariff remains the same (front-end years less than normal, and later years greater) would reduce the initial marketability problems. However, a leveled tariff would mean either that the rate of return on the pipeline would be reduced in the early years and deferred until later years when it would rise, or that special capital structure arrangements would have to be worked out in order to defer some capital charges until later in the pipeline's life.

The President's report says a complete leveling of the tariff would increase the cost of gas to consumers about 20 percent over the life of the project, because the total interest burden would be increased.

The decision whether to level the tariff must be made by FERC in the context of actual financing and tariff proposals made by applicants prior to final certification.

Other tariffs, storage and delivery charges: Once the gas reaches the end of the Alcan line, there will be additional charges for transporting and delivering it to the burner-tip, or the ultimate consumer. These charges depend on where the gas is going, and FERC estimates the charges could range as high as 75 cents per mcf.

AGO 532725

V. TIMING AND RELATIONSHIPS OF GASLINE EVENTS

An understanding of the sequence and cause-and-effect relationships of the various gasline events provides the perspective for dealing with any particular issue. The attached diagram attempts to portray these events and relationships. While it demonstrates that their progression is by no means a single, simple chain, it nevertheless indicates that these events are not hopelessly enmeshed in a complex web of interrelationships.

There is, of couse, some potential for chicken-and-egg stalemates to arise, and there are numerous places where difficulties may require that the entire Northwest project "return to go." Further, it is impossible to place these events on a calendar with any degree of certainty. For example, one of the first events (wellhead ceiling price established) may be resolved tomorrow if Congress chooses to act on the gas-pricing amendments now in conference committee. However, if Congress does not act, it could take FERC 18 months or more to conduct the proceedings and establish the ceiling through existing authorities.

This diagram further reveals two principles which should guide State decisions on royalty sales and pipeline financing:

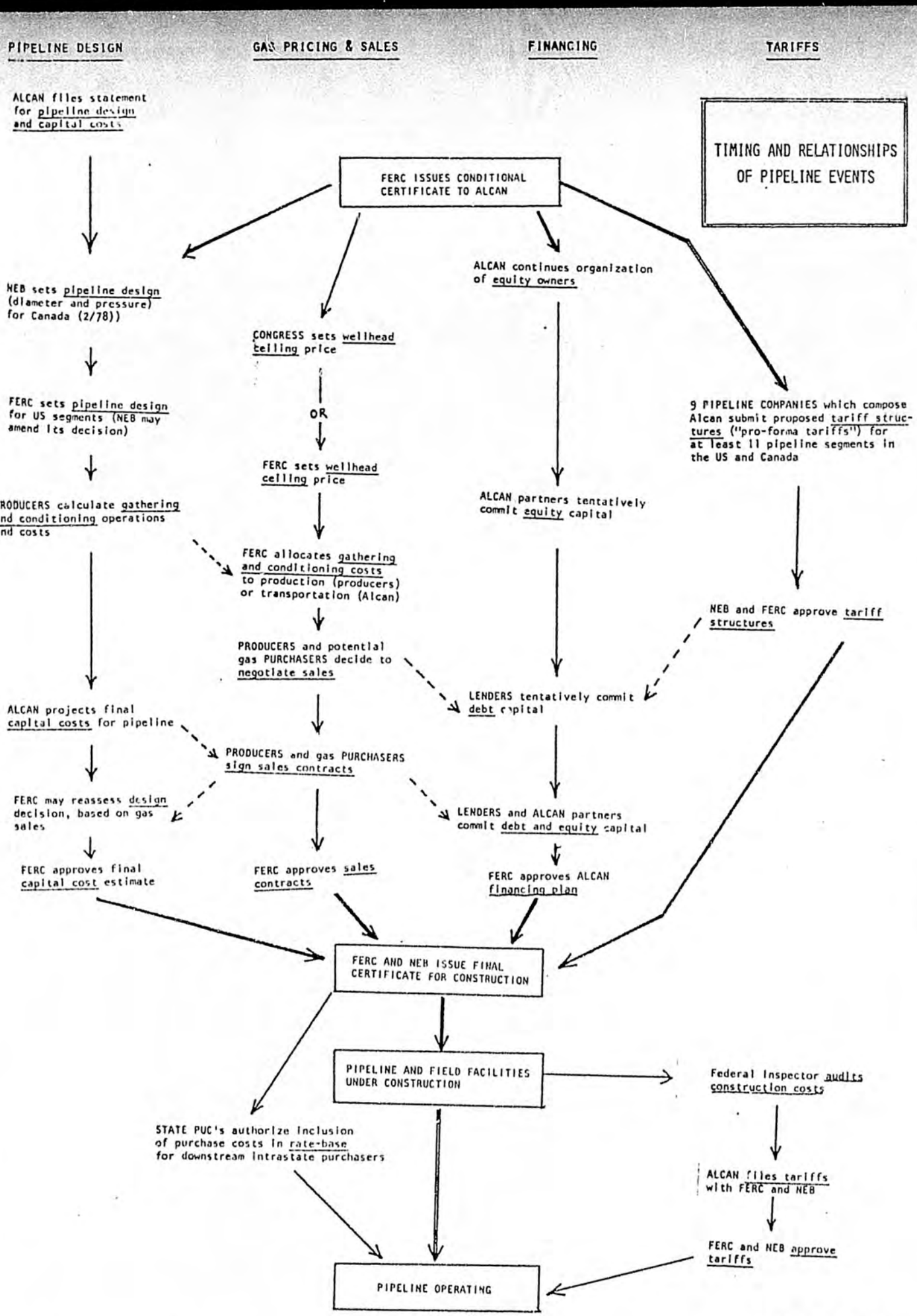
(a) Royalty sales and pipeline financing decisions cannot be made in a vacuum. One cannot determine whether the gasline is a prudent investment without considering the tariff structure,

AGO 532726

capital costs, and overall economic viability. Likewise, State decisions on these matters will affect a variety of other concerns. For example, sale of royalty gas could affect pipeline throughput and, hence, pipeline design. These sales could also influence the financibility of the project in that equity for pipeline construction will be determined in part by the strength of gas purchasers and their interests in joining pipeline consortiums.

(b) Final commitments for gas sales and pipeline financing by involved parties will probably not take place for a relatively long time. This diagram does not necessarily portray the sequence that will occur; instead it portrays the sequence that would occur if decision-making is entirely logical and prudent. One can expect the producers to be prudent in committing their gas. One can also expect private investors to be prudent in committing their money. The State must consider both committing its gas and its money; however, pressures have already developed which may make it increasingly difficult for the State to act in a prudent manner.

AGO 532727


PIPELINE DESIGN
GAS PRICING & SALES
FINANCING
TARIFFS
TIMING AND RELATIONSHIPS OF PIPELINE EVENTS
ALCAN files statement for pipeline design and capital costs
FERC ISSUES CONDITIONAL CERTIFICATE TO ALCAN
NEB sets pipeline design (diameter and pressure) for Canada (2/78))
CONGRESS sets wellhead ceiling price
ALCAN continues organization of equity owners
9 PIPELINE COMPANIES which compose Alcan submit proposed tariff structures ("pro-forma tariffs") for at least 11 pipeline segments in the US and Canada
FERC sets pipeline design for US segments (NEB may amend its decision)
OR
FERC sets wellhead ceiling price
ALCAN partners tentatively commit equity capital
PRODUCERS calculate gathering and conditioning operations and costs
FERC allocates gathering and conditioning costs to production (producers) or transportation (Alcan)
NEB and FERC approve tariff structures
PRODUCERS and potential gas PURCHASERS decide to negotiate sales
LENDERS tentatively commit debt capital
ALCAN projects final capital costs for pipeline
PRODUCERS and gas PURCHASERS sign sales contracts
FERC may reassess design decision, based on gas sales
LENDERS and ALCAN partners commit debt and equity capital
FERC approves final capital cost estimate
FERC approves sales contracts
FERC approves ALCAN financing plan
FERC AND NEB ISSUE FINAL CERTIFICATE FOR CONSTRUCTION
PIPELINE AND FIELD FACILITIES UNDER CONSTRUCTION
Federal Inspector audits construction costs
STATE PUC's authorize inclusion of purchase costs in rate-base for downstream intrastate purchasers
ALCAN files tariffs with FERC and NEB
FERC and NEB approve tariffs
PIPELINE OPERATING

AGO 532728

VI. IMMEDIATE STATE CONCERNS

WHAT SHOULD THE STATE DO WITH ITS ROYALTY SHARE OF PRUDHOE BAY GAS?

A. Timing of Royalty Sales

Of all the gasline events and of all the actors involved, one of the worst "chicken-and-egg" dilemmas is that which confronts the State of Alaska with respect to timing the sale of royalty gas. This is because there are several conflicting demands.

On the one hand, it can be argued that royalty sales should take place relatively late in the sequence of pipeline events when the key questions affecting owner and purchaser interests (such as tariff structures, conditioning cost allocation and final estimates of capital costs) have been resolved. The flow diagram of the previous chapter demonstrates why this is so.

On the other hand, it can be argued that royalty sales should be made rather early in the sequence of pipeline events. This is because pipeline design, which is based on volume throughput assumptions, is a prerequisite to a variety of events (such as calculation of conditioning costs, capital cost estimates, financing, etc.). While producer sales can well be assumed to involve purchasers who intend to carry the gas all the way to the lower states, the destination of State royalty gas is by no means certain. The State has repeatedly declared

AGO 532729

an intent to find destinations for a large portion of its gas in Alaska--including the use of ethane and heavier hydrocarbons in petrochemical industries.[1] This, naturally, causes a great deal of uncertainty for FERC (which must calculate expected gas throughput when setting a pipeline design), and for Northwest and its investors who have a direct interest in the economic viability of the gasline. It is no surprise that FERC and Northwest are already nudging the State to make some decisions.

There are several approaches to this dilemma:

(1) <u>The State could sell its royalty gas relatively early in the pipeline certification process</u>.

Presumably, this approach would assist FERC and Northwest in pipeline planning; however, it may be very difficult to accomplish.

All purchasers for in-state use (especially petrochemical companies considering an Alaska location) may only be willing to make an early sale commitment if the State bears the risks of how subsequent federal and private decisions affecting the wellhead value will turn out. This would virtually preclude

1/ Gas resources for royalty sales should be viewed in two ways: the sale of dry gas versus liquids. Unless a methanol operation is developed in-state, it is a near certainty that Alaska's royalty methane will flow to the Lower 48, either through direct sale or "in-value" taking in which the producers dispose of royalties for the State. However, use of gas liquids (particularly ethane) in-state for petrochemical development has arisen as a possibility.

AGO 532730

the State from being able to find a petrochemical purchaser at an as-yet-unknown "in-value" price.

(2) The State could make an early commitment to remove a portion of its royalties from the gasline at an in-state point, and consummate sales later.

This approach would facilitate FERC's certification of pipeline capacity and design and Northwest's (and investor) financing activities. However, it could also put the State into a box, where it is forced to find a purchaser who is amenable to taking that volume of gas, at the time and at the place it becomes available. If sufficient purchaser interest exists for taking gas under these conditions, "boxing ourselves in" may present no problem. However, if competition is slim or nonexistent, a potential purchaser would have tremendous bargaining strength during State contract negotiations.

(3) The State could sell its gas relatively late in the pipeline certification process.

Under this scenario, the State would, in essence, ignore the desires of FERC and Northwest to establish some degree of certainty with respect to pipeline throughput. There are several reasons why ignoring FERC's interests may not be such a good idea.

(a) FERC has the power to set a tariff structure which could be based on an mcf/mile or zone approach, or which could charge all shippers the full tariff regardless of offtake point. If the latter approach is taken, in-state offtake of royalty gas would be extremely expensive. Nevertheless, FERC might choose to take this approach if it feels it is crucial to the economic viability of the pipeline project. FERC might be

AGD 532731

especially prompted to do so if it has certified pipeline capacity with the expectation that State royalties will be shipped to the Lower 48, and later discovers that the State plans to sell a substantial volume to a purchaser in Alaska. (It should be noted that this same problem now confronts North Pole refinery, which is being charged the full tariff to Valdez even though it ships its purchased oil only to Fairbanks.)

(b) Under normal circumstances, FERC has the power to approve all off-take of gas once it enters an interstate gas pipeline. Currently, Section 13(b) of the Alaska Natural Gas Transportation Act of 1976 exempts Alaska from FERC's powers; however, Congressional action at any time could eliminate this special treatment.

* * * * * *

Timing of Royalty Sales - Putting it in Perspective:

Before determining which course of action to take with respect to the timing of royalty gas sales, the State should explore the relative importance of its decisions. Considerations might include:

(a) How much additional uncertainty would delayed State sale actions really entail, especially in the context of FERC's responsibility to make throughput assumptions about the as-yet-undeveloped Kaparuk, Lisburne and MacKenzie Delta fields, and about the long-term gas production rate of the Sadlerochit (Prudhoe Unit) reservoir itself? If FERC authorizes construction

AGO 532732

of a line designed to carry these supplemental reserves as well as the Sadlerochit, despite the risks involved, how then can FERC assert that the State must decide today future offtake plans for its relatively small volume of royalty gas?

(b) While throughput uncertainties do present some economic problems with respect to who pays how much tariff charges, how much of a problem really exists? With respect to physical considerations, how much flexibility will the pipeline and its compressor stations have to carry more or less gas than their design capacity? What problems are caused by a reduction in throughput volume?

B. State Goals for Royalty Sales and Methods to Accomplish Them

Before the State can reasonably make a sale, it should know what it is trying to accomplish and the alternative methods for doing so. For example, the following list portrays some possible goals and methods to accomplish them. Several goals may be compatible in that they can be accomplished by the same sale procedures. However, others may prove to be mutually exclusive.

(1) Maximizing the purchase price - This approach is best accomplished through structuring a competitive sale with no strings attached. This might negate the inclusion of in-state processing restrictions or the inclusion of options for the State to "take-back" gas volumes at a later date.

(2) Encouraging in-state industrial development (including petrochemicals, fertilizers or methanol) - This approach requires

that a sale be limited to in-state bidders, and it may constrain the price the State can expect to receive for its gas. The State could take further actions which would increase State government involvement in the private sector. This might include building intra-state pipelines to carry royalty gas in lieu of the inter-state Northwest pipeline or as laterals from the Northwest line. It could also include State involvement in an exchange of gas components with the producers at Prudhoe Bay or an exchange of gas volumes with Cook Inlet producers.

(3) Providing for present and future needs of Alaskan residential and commercial consumers - This might require small sales of gas initially; however, the majority of the royalty methane would be taken in-value. The State would also need to secure its right to change an in-value taking into an in-kind taking in the future as Alaskan demand grows.

(4) Preserving future options - No sale commitments would be made under this approach. Instead, gas would initially be taken "in-value" with the intent that "in-kind" sales could be made later. Here again, the State may need to take actions to secure its right to take gas in-kind at a later date.

(5) Enhancing the viability of the Northwest Project - Under this approach, the State would sell its gas to a Lower 48 gas purchaser who was already part of, or who could lend additional equity strength to, the pipeline consortium. The sale would be made when the producers sold their gas, if not sooner.

AGO 532734

WHAT ROLE SHOULD THE STATE PLAY IN FINANCING THE PROPOSED PIPELINE?

The Northwest proposal: Governor Hammond announced April 15th his proposal for immediate State action concerning the financing of the gasline. Under Hammond's plan, which has been worked out and agreed on by Northwest, the State would create an Authority and give it the power to sell $1 billion dollars in tax-exempt bonds on the condition that Congress change the IRS code to allow the bonds to be tax-exempt. The bonds would be secured by revenues to be generated from the pipeline, and the State would have no obligation to repay them in the event the pipeline was not completed. Instead, the bond-holders would be at risk. Hammond proposed that the Authority have the power to sell the tax-exempt bonds without further legislative approval.

Hammond recommended that the State make no equity commitment at this time, but that the Legislature establish an interim committee to study the possibility of equity participation.

Hammond also released an "Agreement between Alaskan Northwest Natural Gas and the State of Alaska," signed by the Governor and McMillian, which outlines 10 actions Northwest agrees to take regarding State concerns.

Reasons to act now:

1. Northwest needs at the very least a show of support or tentative financial commitment from the State in order to encourage participation from other parties. Northwest officials contend that unless the State acts now, the project's chance of

AGO 532735

being financed will diminish significantly.

2. Since the State's regulatory powers over the pipeline are relatively limited, financial participation can provide a vehicle for assuring that an array of State concerns are met. HJR 68, for example, would make State financial participation contingent on a number of conditions, including: the right to in-state takeoff with an mcf-per-mile tariff, a pipeline design capable of carrying liquids, the same advantages for Alaska that other financial participants receive, assurance that Alaskans will have a fair opportunity to provide supplies and services for construction, and allowance for the establishment of a wellhead gas value which, for tax purposes, is equivalent in BTU's to that received for Prudhoe oil. By making its commitment contingent in this manner, the State would be attempting to exert leverage over the federal government as well as Northwest.

3. President Carter and the Congress have said that Alaska, as a major beneficiary of the project, should participate in the financing. Some fear that if Alaska refuses to participate and the project collapses, the federal government will blame the State and take retaliatory action.

4. Pipeline construction will be a significant boost to the State's economy, and therefore the State should do everything it can to assure that the project is built. Northwest officials have testified that the pipeline will mean $20 billion to the State in royalties and taxes over the life of the project,

AGO 532736

up to 10,000 short-term jobs, and other indirect economic and employment benefits. A gas pipeline would open up opportunities for in-state processing and petrochemical development.

Reasons not to act now:

1. The State does not have enough information at this point to make an informed judgment about the economics and viability of the project. Until the federal government (either Congress or FERC) resolves the price of Alaska gas and related questions, many uncertainties will remain. If the congressional energy conference committee does not break its long-standing deadlock in the near future, we can expect a one-and-a-half to two-year delay while FERC addresses these issues.

2. It would be desirable to gain additional production history of the field performance--to make sure that recovery of the gas will not harm recovery of the oil--before an irreversible commitment is made to this project.

3. It is possible the gas will be worth more to the State in the future, in 10 or 15 years, than in the near future. This may not be the State's last and only chance for a gas pipeline.

4. Will the short-term construction jobs and related in-migration be worth the additional impact and drain on State services and resources?

5. Any commitment--however tentative and conditional--will make it more difficult for the State to back out in the future, whatever the reason.

6. Some people have questioned whether it is proper for the State to become so deeply involved in activities traditionally conducted by private enterprise.

7. The North Slope producers have been negative on the idea and apparently do not consider debt participation a sound business investment. In addition, FERC and Northwest both maintain State financing is critical to ensuring debt participation by private lenders. Why should the State be the first to get out front, especially in light of the producers' attitudes? Does the reluctance of private financial institutions to commit money indicate questionable project economics?

8. State financial participation in this project would set a precedent for future projects. The President's report lists this as one of the six reasons to explain why federal financial assistance is undesirable.

Substantive versus non-substantive action: Assuming the State chooses to take some kind of action this year, there are two broad possibilities: (1) polite posturing that supports the project in concept but commits no money, and (2) a substantial equity and debt commitment (subject to future legislative approval) that would enhance the project's chances of success.

The first alternative might be followed if the State concluded: (1) that the project may not be economically viable, or (2) that its benefits to the State are of questionable merit, or (3) that it is desirable that the State appear to be doing something so as not to risk federal retaliation.

AGO 532738

The second alternative would be appropriate if the State concluded: (1) that its economic and employment benefits will be of great value to the State; (2) that the project is probably economically viable (and, hence, is a sound investment); and (3) State participation is critical for project implementation.

Governor Hammond's proposal seems to fall somewhere between these two broad options. Hammond's plan would be less than a full endorsement (and less than Northwest originally sought from the State) since no equity funds would be committed at this time. From the State's standpoint, a decision not to commit equity now seems prudent in light of the many uncertainties and questions about the project's economic viability.

Congress, the federal government and others, however, may not favor the Hammond-Northwest proposal regarding debt participation. The political aspects must be examined, since the whole scheme is contingent on Congress changing the IRS code. Some problems that may arise:

1. Congress is likely to view this proposal, which would allow the issuance of revenue bonds exempt from federal taxation, as a "backdoor" federal subsidy, which already has been explicitly rejected.

Sen. Henry Jackson's Committee on Energy and Natural Resources said in its report on the President's decision selecting Alcan: "The Committee cautions the administration and the sponsors against taking a backdoor approach to federal financing. We

AGO 532739

are, of course, aware of the possibility that the Federal Energy Regulatory Commission may be tempted to devise a new type of tariff, or a special type of wellhead price policy, that would in essence be a 'backdoor' or indirect approach with the same practical effect as direct federal participation in project financing. We intend to monitor the project's progress closely and caution that financial 'gimmicks' involving consumer risk-taking via the federal treasury or via special tariffs will not be tolerated by the Congress."

Northwest officials, however, have said they believe the chances are "reasonably good" that Congress will pass the needed federal legislation. Northwest lobbyist Bill Foster cited amendments in the Senate version of Carter's pending energy legislation that would allow the use of tax-exempt bonds for two other energy projects, including a coal gasification project in the midwest, as an example of congressional flexibility on the matter.

2. The Treasury Department historically has opposed tax-exempt bonding as a means of supporting socially desirable investments, pointing out that the government loses several dollars in tax revenues for each dollar of subsidy provided to a public project through this mechanism. The Treasury Department has proposed, as an alternative, that direct subsidies replace the tax-free bonds, but the misgivings of state and local governments about experimenting with new forms of public debt have so far prevented Congress from implementing the Treasury Department's proposal. The Northwest-Hammond plan would be a

move in the opposite direction by expanding the scope and amount of these tax-free bonds.

Northwest lobbyist Foster acknowledged that Treasury probably will oppose the Northwest-Hammond proposal, but he hopes to persuade the Carter Administration to support it nonetheless because of an overriding national interest that the project be built.

3. The Northwest-Administration proposal may generate opposition from state and local governments throughout the United States. Because a bond offering for this project would add to the total offerings of tax-exempt securities, it is possible this offering could raise the interest costs for all other borrowers in the tax-exempt market.

Foster said it is very unlikely the proposed scheme would have any major impact on the overall tax-exempt market for several reasons. First, he said, the tax-exempt bond market absorbs more than $40 billion in new bonds each year, and an additional $1 billion will not have a significant effect. Second, the $1 billion for this project would be issued over a three-year period, reducing the amount in any one year to about $330 million.

Creating a new Authority: One disadvantage of creating a new Authority, as suggested, is that it would shift debate to the details of the Authority's functions and duties and away from the broader policy questions. Also, the Legislature should examine whether another State entity (like the Alaska Industrial Development Authority) already exists that could issue the tax-exempt bonds as proposed.

Further, creating a new Authority of this type might set an undesirable precedent for other industrial development projects. It has been suggested that Alpetco might try to secure financing for its project through such an Authority, if one existed.

HJR 68: Like the Governor's plan, the approach developed by Legislative Research and embodied in HJR 68 also falls somewhere between substantive and non-substantive action. HJR 68 would commit the State to raise about $1.5 billion by pledging the State's royalty gas in the ground as collateral, an approach first suggested by Northwest officials in February. In contrast to the Governor's plan, HJR 68 would make financial participation in any form directly contingent on a number of State concerns, and would require favorable federal action on a number of pricing and regulatory issues as a condition of State participation.

Perceptions of Investors: In examining these two approaches, one must look not only at State concerns but also at how the financial community is likely to react. Given the many uncertainties about the project, investors may be reluctant to loan money based either on anticipated revenues (Governor's plan) or using gas in the ground as collaterial (HJR 68).

Legislative action: As of June 2, neither the House nor the Senate had taken action to establish the Gas Pipeline Financing Authority suggested by Governor Hammond.

The House Special Committee on the Sale of Royalty Oil and Gas made substantial revisions and additions to the Governor's

AGO 532742

bill (CS HB943) by requiring legislative approval before bonds could be sold and by requiring the authority to submit a "Financial and Alaska Impact Plan" addressing the so-called State concerns.

In the Senate, the Finance Committee modified the Governor's bill by requiring legislative approval before bonds could be sold (CS SB603).

AGO 532743

SELECTED REFERENCES

Unless otherwise noted, the following reference materials are located in the Commissioner's Office, Department of Natural Resources, Office of the Senate President or Legislative Research.

FEDERAL LAWS

Natural Gas Act of 1938

Alaska Natural Gas Transportation Act of 1976

"Approving the Presidential Decision on an Alaskan Natural Gas Transportation System" (SJ Res. 82; HJ Res. 621) (Senate Report 95-567; House Report 95-739) 1977

"Agreement Between the United States and Canada on Principles Applicable to a Northern Natural Gas Pipeline" 1977

GENERAL DOCUMENTS

Decision and Report to Congress on the Alaska Natural Gas Transportation System; Executive Office of the President; 9/77, 271 pp.

Comments on the Decision and Report to Congress: Federal Energy Regulatory Commission; 10/77

FINANCING, ECONOMICS, ANTITRUST

Financing an Alaska Natural Gas Transportation System ; US Treasury Dept; July 1977; 250 pp.

Brief on the Alcan Project on Financing; Alcan; 12/76; 60 pp.

Analysis of Transportation Proposals for North Slope Natural Gas; Arlon Tussing; 3/75; 45 pp.

Report of the Attorney General; July 1977; 100 pp (antitrust).

AGO 532744

PIPELINE DESIGN/ENGINEERING

"Statement of Position Regarding Selection of Pipe for Whitehorse, Yukon to Caroline, Alberta Segment of the Foothills Pipeline", Canadian National Energy Board, 2/78

3/27/78 letter from ARCO to Federal Energy Regulatory Commission

3/9/78 letter from SOHIO to Federal Energy Regulatory Commission

Appendix II Description of Basic Principles of Oil and Gas Processing and a Description of the Prudhoe Bay Oil Field Facilities; Alyeska (located in Assistant Attorney General Bob Maynard's office)

ROYALTY GAS

"State of Alaska Utilization of Royalty Gas"; Bonner & Moore; 1/78

"Utilization of Alaska Royalty Gas & Liquids"; Galliett & Silides; 1/78

MISCELLANEOUS

"Regulatory Treatment of Natural Gas Liquids"; Bob Loeffler; (prepared for the State of Alaska); 3/78

The two documents which set forth the ownership and operating procedures of the Prudhoe Bay Unit are:

(1) Unit Agreement

(2) Operating Plan (2 volumes)

AGO 532745

PLEASE NOTE: THE PRECEDING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

scomm

#14:3

JOINT INTERIM GAS PIPELINE FINANCING COMMITTEE'S REPORT

TO THE FIRST SESSION OF THE ELEVENTH ALASKA STATE LEGISLATURE, 1979:

RECOMMENDATIONS REGARDING DIRECT STATE INVESTMENT

IN THE ALASKA HIGHWAY PIPELINE PROJECT

JANUARY 31, 1979

Legislative Reference Library
Legislative Affairs Agency
Pouch Y State Capital
Juneau, Alaska 99811

AGO 532746

CONTENTS

I. Introduction

II. Summary of Meetings

A. Consultants

B. Committee Highlights

III. Budget

IV. Status of Project

A. Unresolved Issues

V. Recommendations

VI. Appendices

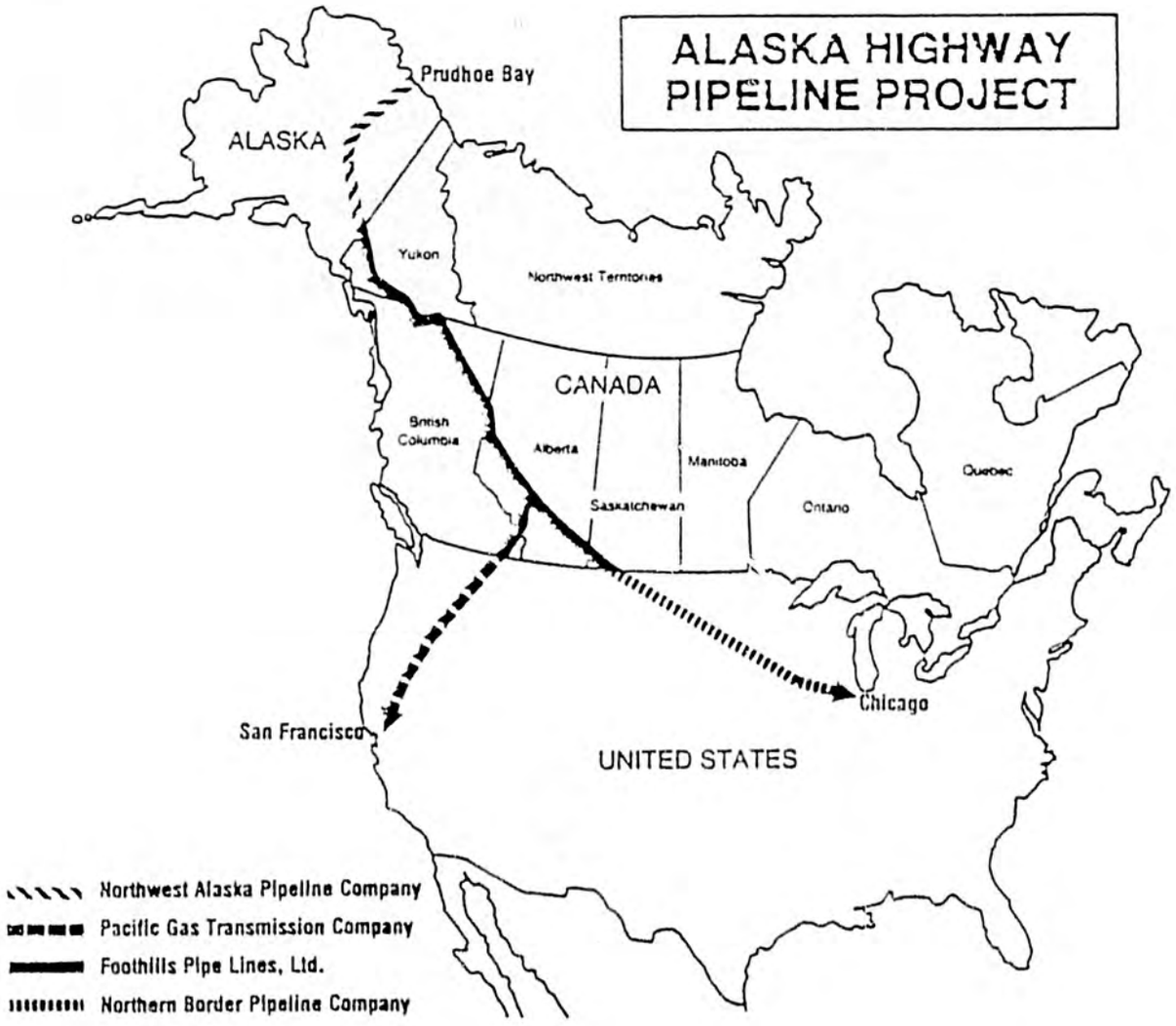
Appendix A. - Legislative Resolve No. 43

Appendix B. - Canadian Travel Report

Appendix C. - Budget Appropriations & Proposed Guidelines

Appendix D. - Budget Expenditures

AGO 532747


ALASKA HIGHWAY
PIPELINE PROJECT
Prudhoe Bay
ALASKA
Yukon
Northwest Territories
CANADA
British Columbia
Alberta
Saskatchewan
Manitoba
Ontario
Quebec
San Francisco
Chicago
UNITED STATES
Northwest Alaska Pipeline Company
Pacific Gas Transmission Company
Foothills Pipe Lines, Ltd.
Northern Border Pipeline Company

AGO 532748

I. INTRODUCTION

On September 20, 1977, Canada and the United States signed a formal agreement to construct a pipeline to carry Alaskan natural gas through Canada to the lower 48 states. Congressional approval for this project, known as the Alaska Highway Pipeline Project, was given November 2, 1977.

The company chosen to build the pipeline, Northwest Alaskan Pipeline Company, through the Governor's office State of Alaska, called upon the 1978 Alaska State Legislature to study the feasibility of providing state financial aid, both through means of creating an authority with the power to issue tax free bonds for investment in the pipeline and through means of maximum $500 million in direct investment.

As a result, the 1978 State Legislature passed Legislative Resolve No. 43 and HCS SCR 102 (See Appendix A). This legislative resolve recognized that a decision made by the state to participate in the direct financing of project during the First Session of the Eleventh Legislature would materially assist the project's planners. In addition, the resolve noted that a direct investment would be a direct commitment of taxpayer's funds to the project and should only be undertaken after the legislature and administration have had a opportunity to review all economic data pertaining to the pipeline, the final financial plan for construction of the entire transmission system and to determine the effects of early withdrawal of gas from the Prudhoe Bay reservoir.

Therefore, in accordance with the legislative resolve, the legislature established a joint interim committee on gas pipeline financing to review and consider possible direct investment by the State of Alaska.

II. SUMMARY OF COMMITTEE MEETINGS

A. Consultants

The Joint Interim Gas Pipeline Financing Committee consists of three members from each house as follows: Senator Mike Colletta and Representative Bill Miles, Co-chairmen: Senator Bill Sumner, Senator Frank Ferguson, Representative Chat Chatterton, and Representative Terry Gardiner. Ex officio members: Mr. Fred Boness of the Dept. of Natural Resources and Mr. Jack Bachman of Northwest Alaskan Pipeline Company, were added by the Committee on September 21, 1978.

The Committee met four times: Sept. 7, 1978 (Anchorage), Sept. 21, 1978 (Anchorage), Nov. 10, 1978 (San Francisco), and Nov. 27, 1978 (Anchorage). Committee meetings were taped and are on file.

With assistance from the Legislative Affairs Agency, the Committee has retained services of six various consultants as follows:

1. The Doscher's Group, Inc.: to be used as an independent technical advisor to the legislature on matters related to oil and gas reservoir management. This group will help determine

the impact of gas extraction on oil recovery from the Prudhoe Bay reservoir.

2. Institute of Social and Economic Research (ISER): ISER of the University of Alaska will analyze the marketability of North Slope gas and the financiability of the project. This study will be headed by Dr. Arlon R. Tussing, who will prepare and deliver a series of interim reports up to June 30, 1979 for the Committee.

3. Merrill, Lynch, White, Weld Capital Markets Group: will provide consulting services for purposes of giving the state insight as to alternative state frameworks that could be used for oil and gas development.

4. Birch, Horton, Bittner, Monroe, Inc.: This Alaska and Washington D.C., law firm will track the federal decisions and perceptions regarding the project.

5. Doug Pope, Esq.: will provide additional specialized legal and consulting services relating to oil and gas pipeline development.

6. Louis Kelso & Co.: is studying the possibility of designing a General Stock Ownership Corporation specifically for financing this project. The Committee wants to know if

such a device may be used as an alternative to direct state investment in the pipeline.

B. Committee Highlights

Committee meeting highlights included comments from Northwest Alaskan Pipeline Company financial advisors regarding the difficulty of putting together financing due to certain governmental delays. Two such delays, the final resolution of the variable rate of return proposal and the IRS exemption for pipeline bonding authority were given careful committee study.

The variable rate of return proposal by the Federal Energy Regulatory Commission (FERC) will determine the amount equity pipeline investors can earn from their investment. The rate of return on invested equity will be relative to the project sponsors cost performance. That is, the lower the estimated cost performance, the higher the rate of return on invested equity.

Congress adjourned last session without approving a change in Section 103 of the Internal Revenue Code. This change will be needed before the state bonding authority can issue 1 billion in tax exempt bonds. The Committee was told by Northwest at its September 21, 1978, meeting that an effort to amend section 103 will be made during the 1979 congressional session.

During the interim period, the President signed into law the Natural Gas Policy Act of 1978. The Committee was told by Dr. Arlon R. Tussing at its Nov. 27, 1978, meeting that he would present an analysis of the Act's impact upon Alaska.

A subcommittee on Alaska hire for the project was created at the Sept. 21, 1978, meeting. The subcommittees purpose is to help insure jobs for Alaskans.

At its Nov. 27, 1978, San Francisco meeting, the Committee met with Mr. Louis Kelso and Co. to discuss the possibility of using a General Stock Ownership Corporation for the gas pipeline project. Such a corporation, if authorized, would give each Alaskan resident shareholder status in the wealth of the project.

Dr. Arlon R. Tussing presented to the committee at its Nov. 27, 1978, meeting a report on what the natural gas industry is, how gas is sold and marketed, how gas projects are financed, and how government regulates the industry. This was the first in a series of reports on marketability and financibility issues.

Also, at its Nov. 27, 1978, meeting Rep. Bill Miles and Mr. Larry Eppenbach of Legislative Affairs Agency gave a travel report concerning their trip to Canada (See Appendix B). After conclusion of their nine- day tour through Calgary, Edmonton, Toronto and Ottawa, the delegation

found that the Canadian portion of the Alaska Highway Pipeline Project is ready to proceed and has the support of the Canadian government.

At the Committee's request, Rep. Chat Chatterton, Greg Erickson of Legislative Affairs Agency and Dr. Todd Doscher, the Legislature's reservoir engineer consultant, met in Denver, Colorado, with H.K. Van Pollen and staff to review progress on the three dimensional Prudhoe Bay reservoir modeling program. Rep. Chatterton reports: "Upon completion of the project in mid April 1979, the state will be in a position to use this sophisticated model to run various appropriate reservoir performance productions, utilizing all geologic reservoir pressure and reservoir performance history available." He notes further, "This will enable us to view reservoir management for the next twenty years... Only two world wide government entities, Algeria and Province of Alberta, will have as near as sophisticated model."

III. BUDGET

For a summary of the Committee's expenditures see Appendix C and Appendix D. As of the end of the fiscal year '79, there exists a remaining balance of $85,977.23.

IV. STATUS OF PROJECT

A. Unresolved Issues

In the weeks to come, careful attention should be given several key unresolved issues regarding the pipeline project. Examples of such issues are as follows:

1. Conditioning Costs: Who will pay for them? Will FERC allow certain conditioning costs to be added on to or taken out of the wellhead price of gas?

2. Variable Rate of Return: Financial assessment of any final order issued by FERC.

3. Mexican Gas Sales: Whether the U.S. Government will allow import of Mexican gas, and if so, its effects on marketability of Prudhoe Bay gas.

4. Natural Gas Policy Act '78: How will this impact Alaska? For example, will it give FERC the power to force producers to meet gas- sale obligations despite harm to oil recovery from the reservoir?

5. Section 103 IRC Exemption: Will Congress permit the sale of tax exempt industrial revenue bonds by Alaska for the gas pipeline project?

6. Socio-Economic Impacts: What will be the benefits to Alaska if the line is built?

7. Gas Sales Contracts: Will the Prudhoe Bay gas producers be

willing and able to assure gas sales commitments?

8. Canadian Gas Exports: Will the Canadian National Energy Board allow export of surplus Alberta gas to U.S. markets?

V. RECOMMENDATIONS

At this time, the Committee cannot give recommendation about direct state investment in the gas pipeline project for critical federal issues remain unresolved, consultant studies are not completed and Northwest has not presented its final financial proposal. More time is needed for careful analysis of the above considerations.

Therefore, it is the Committee's recommendation that it be extended beyond the January 31, 1979, deadline in order to carry out the purpose and intent of Legislative Resolve No. 43, HCS SCR 102.

Senator Mike Colletta

Representative Bill Miles

Senator Bill Sumner

Representative Terry Gardiner

Senator Frank Ferguson

Representative Chat Chatterton

Joint Interim Gas Pipeline Financing Committee

January 31, 1979

APPENDIX A

STATE OF ALASKA

THE LEGISLATURE

1978

Source: HCSSCR 102

Legislative Resolve No.: 43

Relating to a direct investment by the state in the Alaska natural gas pipeline project.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS Northwest Alaskan Pipeline Company has been selected by the President and the Congress of the United States to construct a pipeline to transport Alaskan natural gas from Prudhoe Bay to markets in the lower 48 states; and

WHEREAS the cost of the project is estimated to be 10.5 billion dollars, 3.7 billion dollars of which will be used to construct over 700 miles of pipeline in Alaska; and

WHEREAS timely completion of the Alaska Highway Natural Gas project to transport North Slope natural gas is a matter of vital concern to the nation's energy future; and

WHEREAS construction of the project may produce important social and economic benefits for the people of Alaska, including new jobs, increased state and local tax revenue, enhanced availability of natural gas for Alaskan communities, and stimulus and expansion of private enterprise, including greater potential for development of in-state manufacturing, refining, and processing facilities; and

WHEREAS Northwest Alaskan Pipeline Company has advised the state that it would be of substantial assistance to the company in constructing the gas line if the state were to provide financial aid, both through the means of creating an authority with the power to issue tax-free bonds for investment in the pipeline and through the means of direct investment in the pipeline; and

WHEREAS Northwest Alaskan Pipeline Company has asserted that a direct investment up to a maximum of $500,000,000 in the pipeline would be beneficial to Alaska and would create a substantial

return to Alaskans on the dollars invested; and

WHEREAS, unlike the creation of an authority to issue tax-free bonds, a direct investment would be a direct commitment of taxpayers' funds to the project and should only be undertaken after the legislature and the administration have had an opportunity to completely review all the economic data pertaining to the pipeline, the final financial plan for construction of the entire transmission system and have made a determination as to the effect of early withdrawal of gas from the Prudhoe Bay reservoir; and

WHEREAS, if a decision is made by the state to participate in the direct financing of the project during the First Session of the Eleventh Legislature, this decision will materially assist the project's planners;

BE IT RESOLVED by the Alaska State Legislature that

(1) there is established a joint interim committee on gas pipeline financing to review and consider possible direct investment by the State of Alaska in the pipeline project; the committee consists of three members from each house appointed by the presiding officer of each house; the committee shall elect its chairman;

(2) the committee, in consultation with the governor, shall determine if direct state financial participation in the project appears to be in the best interest of the state;

(3) if it is determined that such participation is desirable, the committee, again in consultation with the governor, shall prepare, and propose to the legislature, legislation to authorize a maximum of $500,000,000 in direct state financial participation;

(4) the committee shall submit a written report to the legislature not later than January 31, 1979.

AGO 532759

THE CANADA REPORT

Information About Canadian Gas and the Canadian Portion of the Alaska Highway Pipeline

Prepared by:

Legislative Affairs Agency
Research Division

January 23, 1979

AGO 532760

TABLE OF CONTENTS

	Page
Gas Reserves	1
Canadian Gas Pricing	3
Past Canadian Government Energy Policy	4
Government in Canada	5
Gas Pipeline Companies in Canada	7
Major Gas Pipeline Proposals	9
Chronology of Canadian Pipeline Route Decision	11
U.S. Canadian Agreement	12
Prebuilding and Gas Export Proposals	15
NEB Gas Supply and Demand Hearings	16
Northern Pipeline Agency	17
Canadian Financing Plans	19
Alberta Heritage Fund	22
NEB Incentive Rate of Return	23
Current Government Policy Toward Pipeline	24
Summary of Pipeline Project	25
Petrochemical Development in Canada	26
Canadian Government Owned Energy Companies	28

AGO 532761

THE CANADA REPORT

Information About Canadian Gas and the Canadian Portion of the Alaska Highway Pipeline

Last November, members of the Alaska Joint Interim Committee on Gas Pipeline Financing traveled to Canada and visited government officials and representatives of the oil and gas industry. This report presents information of general interest the committee acquired while in Canada.

GAS RESERVES

Twenty-three million people live in Canada, almost two-thirds of them in the eastern provinces of Ontario and Quebec. Alberta, in the west, produces 80 per cent of Canadian energy requirements and has 57.9 Tcf (trillion cubic feet) of proven natural gas reserves with ultimate recoverable reserves of gas now estimated to be 110 Tcf.

Last year, the Province of Alberta produced 2.8 Tcf of gas and consumed 20 per cent of it. 45 per cent was shipped to other Canadian provinces and the remainder exported to the United States. The largest gas field now in production in Alberta is the Milk River Field with estimated gas reserves of 9 Tcf.

AGO 532762

Currently there is much speculation about the "deep basin gas deposit" in northwest Alberta. John Masters, President of Canadian Hunter, reported to members of the Gas Pipeline Committee that potential gas volumes as large as 440 Tcf (Prudhoe Bay has 26 Tcf) may be trapped in mesozoic rock sections over 15,000 feet in depth in front of the Foothills overthrust in northwestern Alberta. It is Mr. Masters' opinion that about 50 Tcf is economically recoverable in the deep basin at today's netback price of $1.00 per mcf. At $2.00 per mcf the amount might increase to 150 Tcf. Because of the speculative character of these deposits, they have not been included in the proved or probable reserve estimates. However, the exploratory wells already drilled in the deep basin area are only forty miles from the major Alberta gas distribution pipeline.

Elsewhere in Canada, there have been significant discoveries of natural gas. Two of the largest have occurred in remote areas away from transportation systems.

- The Arctic Islands

The discovery of natural gas in the Arctic Islands occurred on Melville Island in the summer of 1969. In the following ten years close to $600 million was spent to explore this area, $250 of it by Panarctic Oils Ltd. Panarctic, a consortium of thirty companies, has total proven gas reserves of 13 Tcf in the Arctic Islands and they believe that additional reserves at the rate of 2 Tcf/year may be discovered.

AGO 532763

- Mackenzie Delta - Beaufort Sea

Under active exploration since the North Slope oil discovery in the late 1960's, the Mackenzie Delta - Beaufort Sea area has reserves of gas estimated variously from 5.2 to 7.2 Tcf. Exploration is continuing both on land and from an ice-breaking drill ship located in the Canadian Beaufort Sea.

CANADIAN GAS PRICING

Since the energy shortage of 1973 the price of Canadian gas has been regulated at the city gate - literally the price the local distribution company must pay for the gas it distributes to retail customers. Under the Canadian pricing plan, gas producers receive only what is left after transportation charges are deducted from the city gate price in Toronto and federal regulators can precisely control the price the consumers pay for gas locally. This netback approach is just the opposite of the field price regulatory approach used in the United States.

An agreement between the producing Province of Alberta and the federal government fixed the city gate price of gas at 85% of the BTU value of oil. Today's price is about $2.00/million BTU (each cubic foot of natural gas contains about 1000 BTU). In addition, gas exported to the United States has been priced at 100% parity with oil which results in a $2.16/million BTU Alberta border price.

The disadvantage of the Canadian system is that gas producers must swallow the cost of transporting gas and therefore seek high-priced

AGO 532764

local markets. Alberta producers naturally support plans that increase their wellhead value and these include the export of gas directly to the United States.

PAST CANADIAN GOVERNMENT ENERGY POLICY

Between 1971 and 1973 energy industry leaders and ministers were confident that Canada possessed vast reserves of oil and gas. Canada raised her level of oil exports to the United States to 1.3 million barrels per day. The 1973-74 energy crisis, however, illustrated the vulnerability of eastern provinces that depended on foreign sources of crude oil mostly Venezuelan, for their energy. Simultaneously, the Canadian oil industry revised downward their domestic reserve forecasts. The Canadian government thereupon outlined a policy of export restrictions. In January of 1975, the government limited petroleum exports of oil to 800,000 barrels per day and stated that it would favor cutbacks in export of natural gas in case of a domestic shortage even though Canadian producers had contracted to supply gas to the United States until the end of the 1970's.

The Canadian government also tried to reduce Canada's dependence on foreign oil. First, to increase its domestic supply of energy, the government financially supported frontier exploration and new technology to recover energy in deposits such as the Alberta Tar Sands.

More recently, Canadian officials have talked about ways to stimulate the construction of pipelines for moving domestic gas production

AGO 532765

eastward into Quebec and the Maritimes, beyond the present Montreal terminus of the pipeline system. One approach to induce more eastern users presently buying imported oil to shift to gas would be to relax the price controls of gas. However, this idea is plagued with problems including the prospect that Alberta's gas producers wellhead value and hence revenue would be reduced. Eastern provinces, likewise, fear that a reduction in crude oil imports will not enable the now overbuilt refineries running at partial capacity to meet their heavy fixed costs.

GOVERNMENT IN CANADA

Canada is a dominion of provinces linked together by the "British North American Act of 1867" which serves as its constitution. Canada also has an unwritten constitution comprising many of the legal rights and procedures employed today. The country is run from Ottawa by a parliament composed of a 265-member elected House of Commons and a far less important 102-member appointed Senate. As in the English parliamentary system, no separate executive exists and the Prime Minister and his cabinet are all members of the majority party of parliament. All measures introduced by the Prime Minister to parliament are passed substantially unamended as the Prime Minister controls the majority. The cabinet has about 16 ministers, each responsible for one or more departments, or portfolios. Cabinet members are required to appear several times a week for the daily question period in parliament. The

AGO 532766

departments themselves are often run by deputy ministers or civil servants, typically of long standing.

Provincial governments in Canada, more powerful than state governments in the U.S., have generally the same parliamentary structure as the federal level although without an upper house. The Alberta legislature, for example, consists of 75 elected representatives.

There is also a vast array of regulatory agencies in Canada. At the federal level the National Energy Board (NEB) is similar to the Federal Energy Regulatory Commission in the U.S. Created in 1959, the NEB has 9 commissioners, a staff of 325, and is responsible for regulating pipeline tariffs and approving oil and gas exports (subject to cabinet approval).

The Foreign Investment Review Agency reviews major project proposals and mergers to make sure that the high percentage of foreign investment in the Canadian energy industry does not increase.

At the provincial level there are regulatory bodies similar to "public utility commissions" of most U.S. states. In addition, Alberta created the Alberta Energy Resource Conservation Board which appraises reserves and regulates exploration, development, and pipelines within the Province. The Alberta Petroleum Marketing Commission is the single marketer of oil and gas exported from Alberta. The Commission purchases and then resells oil and gas allowing the producer to receive the average mix of domestic sales and export prices.

AGO 532767

GAS PIPELINE COMPANIES IN CANADA

- Trans-Canada Pipeline

A special act of parliament in the late 1950's created the Trans-Canada Pipeline Company which operates the only gas pipeline carrying gas from the Alberta border east across Canada into Ontario Province and Montreal. The Trans-Canada system consists of looped 30" and 36" pipelines for most of the distance from Alberta to Toronto and then 20" and 24" pipelines from Toronto to Montreal. These pipelines are now owned privately and operated as a public utility, although a portion of the system was originally owned by the federal government. Trans-Canada was recently awarded a 22½% increase in its tariffs which will allow it to make a profit and be liable to pay income taxes for the first time. However this increase absorbed most of a gas price increase Alberta gas producers had been anticipating, worsening the already tense relations between western producers and eastern gas purchasers. The pipeline charges 59¢ per mcf to move gas from Alberta Province to Toronto, and has a surplus daily throughput capacity of about 300 mmcf/day.

- The Alberta Gas Trunkline Company Ltd. (AGTL)

Formed by an act of the Alberta government in 1964, AGTL owns and operates a major system of gas pipelines in Alberta Province. The system comprises approximately 6000 miles of major trunklines and laterals ranging in diameter from 3" to 42". The Company enjoys a monopoly

AGO 532768

position as the only builder and operator of pipelines in Alberta for export of Alberta gas. AGTL, however, is far more than a gas pipeline company. It owns, for example, a small oil and gas producer in western Canada, and is constructing a $350 million ethylene plant in Joffre, Alberta, with a design output of 1.2 billion pounds of chemicals per year.

AGTL recently acquired controlling ownership of Husky Oil Company, a fully integrated oil and gas company. Husky Oil has major heavy crude oil development projects in Lloydminister, Alberta, and extensive oil drilling efforts on the North Slope of Alaska. Husky also operates five refineries and a substantial pipeline network of its own. The acquisition of Husky Oil by Alberta Gas Trunkline makes AGTL one of the major oil and gas companies in Canada.

- Westcoast Transmission Ltd.

Begun in 1949, Westcoast Transmission Company Ltd. is the major owner and operator of natural gas pipelines in British Columbia. Westcoast buys virtually all of the oil and gas produced in British Columbia and also purchases gas directly from Alberta Province. The Company owns 1,376 miles of transmission lines and 962 miles of gathering lines as well as several natural gas processing plants. Westcoast Transmission is 10% owned by the British Columbia government and 34% owned by Pacific Petroleum Limited which in turn was recently acquired by Petro-Canada (see later section on government owned oil companies).

AGO 532769

MAJOR GAS PIPELINE PROPOSALS

- Polar Gas Project

The owners of the Arctic Island gas reserves propose to transport the gas by high pressure (1680 psi) 42" pipe 2,338 miles south along the west coast of Hudson's Bay to connect with the Trans-Canada Pipeline system in Ontario Province. The Polar Gas Pipeline is designed to carry 2.1 bcf/day expandable to 3 bcf. Supported principally by Panarctic Ltd. and Trans-Canada Pipeline, the Polar Gas Project has been postponed due to the lack of sufficient reserves to support the proposed through-put rate. Present estimates of the completion date for this project now fall between 1990 and 1995.

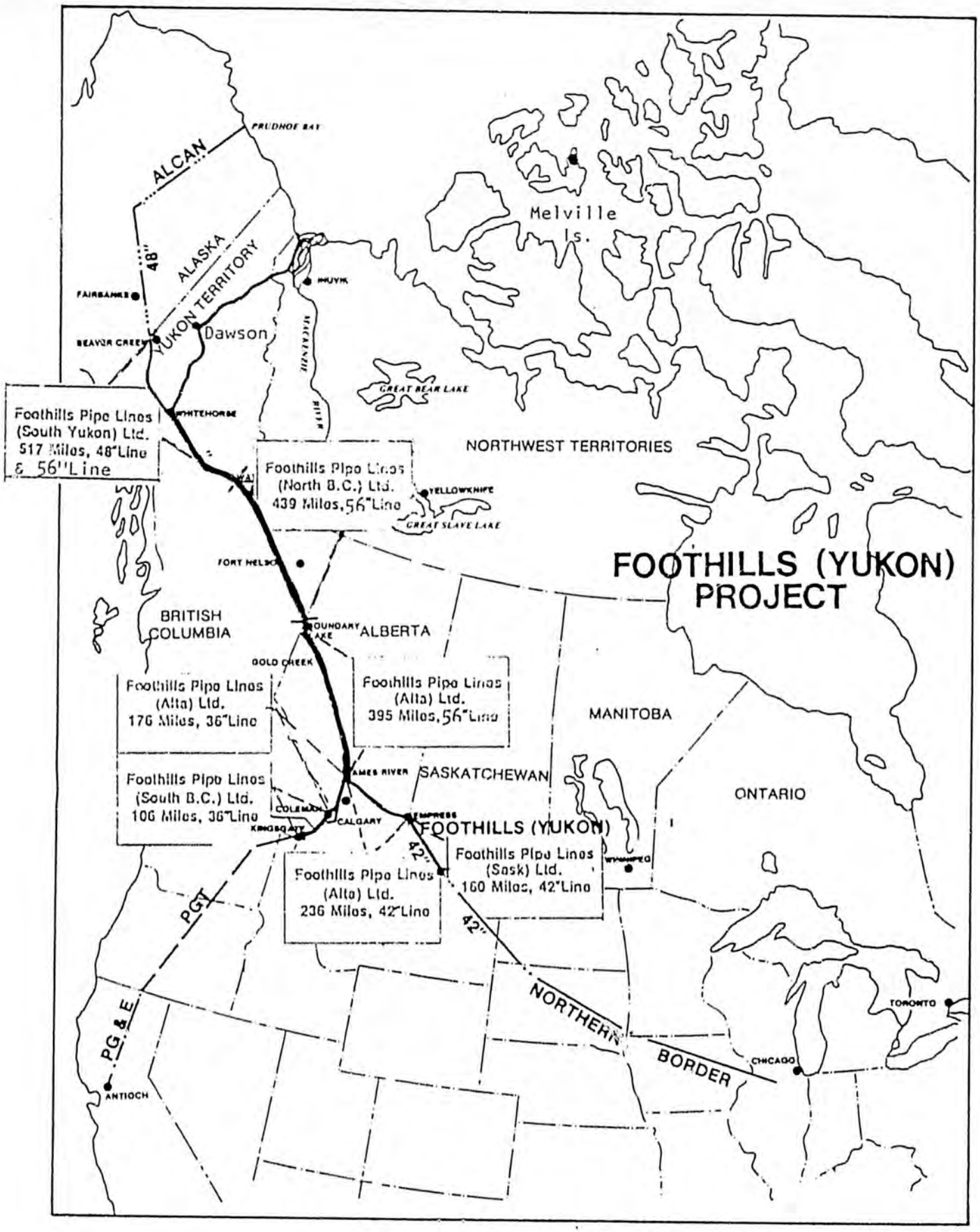
- Q & M Pipeline Proposal

This proposal would extend the Trans-Canada Pipeline system east into Quebec, New Brunswick and Nova Scotia - a total of 1,250 miles of various size pipe. Beside bringing natural gas to eastern Quebec and the Maritines for the first time there is also a provision in this proposal to supply Maine and northern New England with up to 250 mmcf/day of gas.

- Foothills Pipeline (Yukon) Limited

This is the Canadian portion of the Alaska Highway gas project. In its present configuration it comprises 2,023 miles of 36", 48" and 56" pipe.

AGO 532770



PRUDHOE BAY
ALCAN
48"
ALASKA
YUKON TERRITORY
FAIRBANKS
BEAVER CREEK
Dawson
INUVIK
MACKENZIE RIVER
Melville Is.
GREAT BEAR LAKE
WHITEHORSE
Foothills Pipe Lines (South Yukon) Ltd. 517 Miles, 48"Line & 56"Line
Foothills Pipe Lines (North B.C.) Ltd. 439 Miles, 56"Line
NORTHWEST TERRITORIES
YELLOWKNIFE
GREAT SLAVE LAKE
FORT NELSON
FOOTHILLS (YUKON) PROJECT
BRITISH COLUMBIA
BOUNDARY LAKE
ALBERTA
GOLD CREEK
Foothills Pipe Lines (Alta) Ltd. 176 Miles, 36"Line
Foothills Pipe Lines (Alta) Ltd. 395 Miles, 56"Line
MANITOBA
AMES RIVER
SASKATCHEWAN
Foothills Pipe Lines (South B.C.) Ltd. 106 Miles, 36"Line
COLEMAN
CALGARY
KINGSGATE
EMPRESS
FOOTHILLS (YUKON)
ONTARIO
42"
Foothills Pipe Lines (Sask) Ltd. 160 Miles, 42"Line
WINNIPEG
Foothills Pipe Lines (Alta) Ltd. 236 Miles, 42"Line
PGT
42"
NORTHERN BORDER
TORONTO
PG & E
CHICAGO
ANTIOCH

AGO 532771

A 48" pipe will receive Alaska gas at the Alaska-Yukon border and proceed along the existing Alcan Highway to Whitehorse in the Yukon Territory. From Whitehorse to St. James River near Calgary, Alberta, the line will increase to 56" in order to accommodate Canada's Mackenzie Delta gas. (The Mackenzie Delta gas if produced will be moved to Whitehorse in the "Dempster Line" designed to move approximately 1.2 bcf/day.) The Foothills line will divide into two legs at St. James River with about two-thirds of the gas flowing east through a new 42" pipeline, and the rest heading west through B.C. and then south into the U.S.

CHRONOLOGY OF CANADIAN PIPELINE ROUTE DECISION

-In 1972 a number of separate companies formed Canadian-Arctic Gas Limited. In 1974 they proposed to build a 48" pipeline carrying both Canadian and Alaskan gas to southern markets following the Mackenzie Valley.

-In mid 1974 Alberta Gas Trunkline decided to leave this consortium and together with Westcoast Transmission Company of Vancouver formed Foothills Pipeline Limited Company to sponsor the "Maple Leaf Project" - a 42" low pressure pipeline to bring only Mackenzie Delta gas south to link up with their existing systems. The Maple Leaf proposal was filed in the spring of 1975.

-The "Berger Inquiry" which as early as 1974 had begun to assess the environmental and regional impacts of the northern pipelines was

AGO 532772

joined by the Canadian National Energy Board (NEB) which began hearings on the two Mackenzie Valley proposals.

-In August of 1976, Foothills and its U.S. partner proposed to build a 42" pipeline to carry gas from Prudhoe Bay to Fairbanks and then by the Alaska highway route to northern B.C. and Alberta, at which point the gas would be moved through existing pipelines.

-In February of 1977, Foothills submitted its "Express Line" proposal which planned a 48" line to convey gas directly from Prudhoe Bay to the U.S. border in a single new "express" line.

-The Berger Inquiry Report was released in April of 1977. It argued against the Mackenzie Valley route proposed by Arctic Gas on environmental and social impact grounds.

-In a report dated July 1977 the NEB selected the revised Alaska highway proposal "the express line" provided that it be rerouted northward to pass through Dawson City, thus reducing by a third the required length of the Dempster line from the Mackenzie Delta. The NEB further required that the applicants file an application by July 1, 1979, to build this Dempster lateral line.

-September of 1977 President Carter selected the Alcan project (including Foothills) to transport Alaskan gas to the U.S.

U.S. - CANADIAN AGREEMENT

Routing the pipeline through the Yukon south along the Alaska highway rather than north along the Klondike highway as proposed by the

NEB will lower the cost of transporting Alaska gas. The southern routing, however, added to the length of the Dempster lateral required to bring Mackenzie Delta gas into the system. This was one of the reasons an "agreement in principle" was worked out between the government of Canada and the United States. It was agreed that shippers of Prudhoe Bay gas would pay part of the cost of service for shipping Canadian gas from Dawson to Whitehorse to compensate Canadians for the extra distance of pipeline required by the U.S. route preference south along the Klondike highway through Dawson City. Cost overruns for constructing this line exceeding 35% will reduce the U.S. shippers share.

The agreement in principle also provides that a technical study group determine the pipe capacity and pressure. The Canadian government supported a large diameter (56") low pressure (1080 psi) line while the U.S. supported a smaller diameter high pressure pipeline. The second choice of the U.S. technical team, however, was the 56" 1080 psi pipeline.

The Canadian National Energy Board on February 17, 1978, chose the large diameter (56") pipe for the portion of the line from Whitehorse south to where it splits into eastern and western legs. Even though this 56" pipeline will operate at a pressure of 1080 psi, its capacity to carry heavy gas hydrocarbons will probably be as great as the Alaska portion of the line because it will operate at a minimum of 40 degrees Fahrenheit. The Alaska portion will have to be chilled below the freezing point of water to avoid melting the permafrost which extends only 100 miles into Canada.

The selection of a large diameter relatively low pressure pipeline has obligated the Alaska gas producers to build a gas conditioning plant in Prudhoe to remove most of the CO_2, water and gas liquids before shipping gas.

Canadian Content Regulations

Interestingly, only two North American companies are capable of rolling the 56" pipe specified for the Canadian portion of the line. They are both Canadian: the Interprovincial Steel and Pipe Corporation Ltd. and the Steel Company of Canada Ltd. In addition, the NEB adopted regulations to be sure that Canadian firms and workers would receive the maximum economic benefit from pipeline projects in Canada. These "Canadian content" regulations were somewhat at odds to the "agreement in principle" between Canada and the United States which committed each government to the principle that goods and services for the pipeline would be supplied on generally competitive terms. Negotiation on this point is still being conducted by federal agencies in Washington and the American Embassy staff in Ottawa. However, it is clear from regulations issued and agreements already reached that the "Canadian Content" (of the goods and labor supplied) for the portion of the pipeline traversing Canada will be not less than 90%. Both an intensely national orientation on this issue as well as the weakness of the Canadian dollar (making their labor and capital more competitive) have contributed to this imbalance in content.

AGO 532775

PREBUILDING AND GAS EXPORT PROPOSALS

Foothills and Northwest hope to "prebuild" the southern Canadian and U.S. sections of line before the Alaskan and Yukon sections are completed. Prebuilding would lengthen the construction period and reduce the competition for available labor and material as well as provide an early cash return to investors in the prebuilt segments if the prebuilt sections were put into immediate use exporting Alberta gas to the U.S.. For prebuilding to commence gas purchase contracts must be signed between Alberta gas producers and U.S. gas distribution companies and contracts to transport the Alberta gas must be negotiated. These contracts, in turn, depend on export permission being granted by the National Energy Board and by the Energy Conservation Board of Alberta Province. In the U.S., the Federal Energy Regulatory Commission has already given "conditional approval" to the Pan Alberta export plan--one of only several proposals pending.

- Pan-Alberta Gas Limited

Pan-Alberta is a company 60% owned by Alberta Gas Trunk and the remainder by Alberta Energy Company Limited. Its export proposal relies on the "prebuilding" the Foothills pipeline and proposes to export 1.04 bcf/day over an initial contract term of six years subject to an extension of an additional six years.

AGO 532776

- Pro-Gas

This proposed export plan is sponsored by a group of ten natural gas producers for between 300 and 700 mmcf/day using existing excess capacity of the Trans-Canada Pipeline. This plan is in direct opposition to prebuilding the eastern leg of the Alaska Highway pipeline unless the NEB approves sufficient gas exports for both to go forward. The Alberta gas producers support the Pro-Gas approach because their netback price will be higher using the existing Trans-Canada line rather than new southern portions of the Alaska highway gas pipeline.

- Sulpetro

A third and much smaller export proposal also plans to use the Trans-Canada Pipeline to transport gas for a three year period. Sulpetro has applied to the NEB for export permission utilizing the Trans-Canada line. Trans-Canada, however, has argued that this export proposal is not compatible with the Pro-Gas proposal it supports.

NEB GAS SUPPLY AND DEMAND HEARINGS

The Canadian National Energy Board on the 11th of September, 1978, completed a major study of "Canadian Oil Supply and Requirements" at the request of the federal minister of Energy, Mines and Resources. They last reported on gas in April of 1975 when they projected insufficient Canadian production of gas to meet U.S. import and Canadian domestic

AGO 532777

needs by the late 1970's. Since then the supply of Alberta gas has increased due to productive exploratory efforts funded in large part by gas price increases. The existence of this additional gas (called "bubble gas") together with the pending applications for exports caused the National Energy Board to commence In October of 1978 an extensive public inquiry into Canadian gas supply and demand. The Board indicated that it intends to make its recommendations available by February of 1979 with respect to the existence of a gas surplus and the prudence of exports. Should a gas surplus exist, export proposals will then be considered with a final ruling expected by July. The final determination of any export plan, however will rest with the Prime Minister and cabinet. Prime Minister Trudeau is expected to stand for re-election during the summer and the final decision therefore will not likely be made before the fall of 1979.

Although the preponderance of testimony at the hearings has been in favor of exporting Alberta gas, members of the Board were not willing to speculate on their decision when interviewed by the Alaska delegation.

NORTHERN PIPELINE AGENCY

Following the agreement in principle in the fall of 1977, the Canadian parliament passed bill C-25 establishing the Northern Pipeline Agency to facilitate the planning and construction of the pipeline. The Northern Pipeline Agency was empowered to carry out the requirements of

AGO 532778

the agreement between Canada and the United States. Heading up this one window regulatory agency in Ottawa is Commissioner Mitchell Sharp, an experienced senior public servant who has held several Canadian cabinet posts. In the Calgary office, Harold Millican serves as the agency administrator along with Bill Scotland who is the delegated representative from the NEB. These members of the Northern Pipeline Agency indicated to the Alaska delegation that substantial progress had already been made on the subjects of Native settlements, local hire, and pipeline procurement.

Native Claims

Detailed discussions are underway with Native groups in the Yukon and the Northwest Territories. The Pipeline Agency believes that a final settlement with the Yukon Indians may not be possible prior to the start of construction of the pipeline. While parliament has established a policy to resolve the Native Claims, the Canadian courts have not recognized their legal basis. Thus Native groups in Canada do not have the power to halt construction of the pipeline via court imposed injunction.

Local Hire

Native northerners who have lived in the Yukon or the Northwest Territory prior to August 1, 1977, are specifically provided a preference for hire. In addition the Northern Pipeline Agency has estab-

lished regulations requiring non-local construction workers to be hired for the pipeline only in Edmonton and Calgary and not in Whitehorse or Dawson. The Northern Pipeline Agency is continuing to hold hearings on these and related matters throughout the Yukon and Northwest Territories.

CANADIAN FINANCING PLANS

Before granting approval to the Foothills (Yukon) Pipeline Ltd. proposal the NEB suggested an organizational structure wherein Alberta Gas Trunkline and Westcoast Transmission Ltd. combined to own Foothills Yukon Ltd., which would in turn contract with AGTL, Westcoast and other firms to construct and operate pipelines over the terrain and conditions with which each is experienced. This structure allows Foothills (Yukon) Ltd. to use the liability limiting features of project financing.

Alberta Gas Trunkline Co. and Westcoast Transmission Co. each own half of Foothills Pipeline (Yukon) Ltd. and an additional interest in the five subsidiary companies Foothills formed to build each segment of the line. Ownership of the subsidiary companies varies; AGTL controls the most shares of the companies building in Alberta and Southern B.C. while Westcoast Transmission controls the Northern B.C. subsidiary. The remainder are jointly controlled. The following table displays the ownership composition of the companies:

AGO 532780

	Ownership Interest			Net Ownership Interest*	
	Foothills Pipeline (Yukon) Ltd.	AGTL	Westcoast	AGTL	Westcoast
Foothills Pipeline (south Yukon) Ltd.	100%			50%	50%
Foothills Pipeline (north B.C.) Ltd.	51%		49%	24.5%	75.5%
Foothills Pipeline (south B.C.) Ltd.	51%	49%		75.5%	24.5%
Foothills Pipeline (Alberta) Ltd.	51%	49%		75.5%	24.5%
Foothills Pipeline (Saskatchewan) Ltd.	100%			50%	50%

* Net ownership interest recognizes that AGTL and Westcoast each own half of Foothills Pipeline (Yukon) Ltd.

Investment Cost of Canadian Section of Pipeline

Cost estimates which are now obsolete due to last year's delay in construction were presented to the White House staff on August 2, 1977. No more current estimates are available.

Foothills Pipeline (Yukon) Ltd. (Estimates in millions of Dollars)

	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Canadian Banks	-	117	319	106	-	542
U.S. Long Term Debt	-	341	1,103	782	-	2,227
Canadian Long Term Debt	80	106	106	-	153	445
Canadian Common Stock	234	183	227	158	7	855
	314	747	1,800	1,046	160	4,069

AGO 532781

In 1977 the major part of the debt financing--$2.2 billion or 80%--was planned to be sold in the United States. Since then (principally due to delay in the pipeline project) the total amount of debt to be issued has increased. At a meeting with financial advisors to Foothills (Yukon) Pipeline Ltd. (notably Dominion Securities, First Boston Corps., McCloud Young Weir Company, and Pittfield McKay Company), members of the Alaska delegation were told that a large share of the long term debt would be placed in the United States to take advantage of lower U.S. rates. The long term difference or "spread" in interest rates has averaged 1½% and although the current interest differential is much less than that (½ of 1%) the financial advisors see no reason the traditional spreads would not return. In addition, they see no difficulty in Alberta Gas Pipeline or Westcoast Transmission Company obtaining financing due to the current high interest rates or the strength of their credit.

This was somewhat surprising due to the heavy capital outlay AGTL sustained to purchase control of Husky Oil Company. Meetings with independent advisors (notably the A.E. Ames Company) however, confirmed the view that there are no real impediments to either AGTL or Westcoast Transmission borrowing the equity funds needed to finance their portion of the line--now estimated to be over $400 million apiece. However, they did indicate the need to develop guarantees to ensure that revenues would be forthcoming when the pipeline is completed to the Alaska border even if the Alaska segment has not yet been connected.

Ames also indicated that Alaska financial participation, although not "necessary" to the pipeline, would be "beneficial" to the overall project financing efforts.

ALBERTA HERITAGE FUND

The Alberta Heritage Savings Trust Fund is Alberta's permanent fund. Thirty percent of the non-renewable resource revenue coming to the province is transferred to the Heritage Fund to be invested and saved for Albertans in the future. The Heritage Fund which held $3.6 billion in assets as of June 30, 1978, has not been asked to invest in either the debt or equity portions of the Foothills (Yukon) Pipeline. When the fund managers were asked by the Alaskan delegation if they would be interested in such an investment they indicated that they expected to receive and would review an investment proposal on the debt portion of the pipeline but that they would not consider an equity investment. Such investment decisions would be made by the Premier and cabinet of Alberta Province in any case, and a minister of the cabinet indicated that the administration would not be interested in an equity investment under any circumstances.

No estimate was available of the amount of funds the Heritage Fund might contribute, if any, to purchase pipeline bonds. The following summary balance sheet describes current assets by major category of the Alberta Trust Fund as of June 30, 1978.

Alberta Heritage Savings Trust Fund

Assets as of June 30, 1978.		Millions of Dollars
Current:		
Deposit in Cash Investment Trust Fund of the Province of Alberta		138.7
Marketable Securities including accrued interest		2079.0
Short term	568.3	
Government & Corporate Bonds	78.9	
Alberta Municipal Financing Corp.	575.8	
Alberta Government Telephone	708.4	
Other Provinces	91.0	
Capital Project Division Investments (research projects, health care, irrigation, etc.)		138.3
Canada Investment Division Investments (loans to other provinces)		96.3
Alberta Investment Division Investments		
Alberta Housing Corp. debentures		267.9
Alberta Home Mortgage Corp.		396.7
Other, including equity in Syncrude Project (tar sands) and Alberta Energy Co.		486.8
TOTAL		$3603.7

Over the next year the fund is expected to receive $1 billion in contributions of oil revenue and earn an additional $295 million from investments.

THE NEB'S INCENTIVE RATE OF RETURN

Last fall the NEB adopted an incentive rate of return formula for the Canadian portion of the pipeline that, while patterned after the U.S. version, does have some differences. The sliding scale rates are

AGO 532784

1-3% higher on the average than FERC's and suggest returns on the average of 16-24%. However, these rates will apply to cost estimates of the pipeline already filed by Foothills (Yukon) Ltd. and unlike the U.S. agency the NEB does not provide for a major revision to the original estimates. Therefore the actual dollar returns to the companies may not be as high using the Canadian approach than had they followed the U.S.. Godfrey Edge, Vice Chairman of the NEB indicated that the NEB supported the incentive return concept.

CURRENT GOVERNMENT POLICY TOWARD THE PIPELINE

Discussions between members of the Alaska delegation and officials in the Ministry of Finance and the Ministry of Energy, Mines, and Resources gave us a clear understanding of the attitude of the present administration toward the pipeline across Canada. First they see no need for, nor any desire to provide financial support to the pipeline. Second, they favor and support the pipeline only insofar as it brings Alaska gas to U.S. markets. Although the pipeline would provide a method (the Dempster lateral) to bring Mackenzie Delta gas to markets in the south, most Canadians view this as a long run residual, something that might become important in the 1990's. Further there are some Canadians who suggest that the Dempster lateral is not an economic method to transport Mackenzie gas. They suggest that an eventual Mackenzie Valley pipeline or a northern "Y pipeline" connecting both the

AGO 532785

Arctic Islands and the Mackenzie Delta would serve Canadian interests best. It is understandable, therefore that Canadians have argued aggressively that the content of construction of the line in their country be maximized as this is their most tangible present benefit of the line.

There is a growing apprehension in Ottawa that the northern portion of the pipeline will never be completed and that the project will become a means of transporting precious Alberta gas southward to the U.S. rather than eastward into the population centers of Canada. All the government officials at the National Energy Board as well as the Department of Energy, Mines, and Resources stated that only upon satisfactory completion of gas sales contracts and the establishment of financial commitments that assured completion of the entire pipeline would the Canadian government consider allowing prebuilding of the Alaska pipeline to commence.

SUMMARY OF PIPELINE PROJECT

In summary after extensive consultations with industry and government officials, it became clear to the Alaska delegation that the Canadian portion of the pipeline would be ready to proceed if and when the U.S. portions were ready. The Canadian government has moved swiftly to meet its regulatory responsibilities, and the financial community in Canada appears willing to finance the equity portion of the pipeline in the event suitable gas purchase and transportation contracts can be negotiated.

AGO 532786

PETROCHEMICAL DEVELOPMENT IN CANADA

Because of the interest generated last year during the legislature's consideration of the Alpetco contract, the Alaska delegation inquired about petrochemical developments in Canada.

Petrochemicals are derived from crude oil and natural gas and include ethylene, propylene, benzene and their derivatives. These chemicals are used to build plastic products, fibers, rubber products, and a broad range of other formulated products.

Petrochemical facilities tend to be built in large complexes because of the dependence of one product being used as a raw material for another. The center of petrochemical production in Canada is in Sarnia in southwestern Ontario. Canada's major ethylene plant, Petrosar is located in Sarnia. The plant uses Alberta crude oil as a feedstock to produce ethylene. It is now operating at only one quarter of capacity and losing money due to worldwide marketing problems caused by the oversupply of ethylene and due to additional difficulties in marketing the by-products of ethylene manufactured from a crude oil feedstock. The by-products, called "heavy ends", are in direct competition with products from Canadian refineries which at present have capacities far in excess of market needs. Petrosar was first owned by Dow Chemical, but now Petro-Canada (the government owned oil company) owns a substantial equity position.

AGO 532787

A cautionary note was sounded by every government official that the Alaska delegation talked to about petrochemicals and they cited several examples to support their case. One was another "world scale" ethylene plant scheduled to begin operations late this year in Red Deer, Alberta. This will use ethane rather than oil as its feedstock. The plant will be owned by a subsidiary of Alberta Gas Trunkline although the plant was financed by Dow Chemical who is also committed to purchasing the products on a take-or-pay cost of service basis, thereby relieving AGTL of any marketing risk.

The Province of Alberta conditioned an authorization for Dow to purchase and export raw ethane from Alberta with a commitment by Dow to build a plant and process a quantity of ethane within the Province. Nevertheless it is now recognized that while provincial leveraging may have been sufficient to get the plant built, it won't guarantee a thriving operation. On the contrary, severe marketing problems are foreseen when the plant goes on stream until the market price of ethylene increases substantially. In the meantime the capital structure of Dow Chemical will have to support this marginal enterprise. This point - that of having a major chemical company participate in any petrochemical project was made repeatedly by Canadian officials.

A different approach is being developed by the Alberta Energy Company, which is a newly created company 50% owned by the Alberta government. This company is proposing to produce benzene using natural gas liquids as feedstock in a joint venture with Mitsubishi, a Japanese

trading company. However it proposes a "gimmick" for its project whereby the by-products of benzene production would be sold for manufacture into synthetic natural gas. The sale of those by-products would yield at a price high enough to offset the losses on the benzene. The company now says that what started off to be a benzene petrochemical project has turned into an SNG export plan, with benzene produced only as a by-product.

CANADIAN GOVERNMENT OWNED ENERGY COMPANIES

The energy crisis of 1973 caught the Canadians at a particulary bad time. Their vast tar sand deposits required new technology to produce and their frontier oil and gas deposits needed years to develop. Although the rapidly increasing fuel prices made such undertakings feasible there was a lack of leadership and direction. At the same time estimated reserves of oil and gas from conventional fields, once believed reliable, were adruptly scaled down, spawning even greater insecurity about future supplies.

Petro-Canada

In response to these needs the House of Commons approved creation of the Canadian National Petroleum Company (Petro-Canada) on July 10, 1975. The Company became a crown corporation of Canada completely owned by the federal government and capitalized initially with $500 million

AGO 532789

and given additional power to borrow $1 billion from the Treasury. The Corporations's mission was to generate new supplies of oil and gas for Canada particularly in areas requiring high technology.

Appointed to run Petro-Canada was Maurice Strong, of U.N. fame as chairman and Wilbert Hopper as president and now chief executive officer. Mr. Hopper worked with Foster and Assoc., a petroleum reporting service in the U.S. and Canada and joined Arthur D. Little in 1965 before becoming Assistant Deputy Minister for Energy Policy in Ottawa. Interestingly, while at Arthur D. Little, Mr. Hopper worked for a time in Juneau for governor Wally Hickel.

Under Hopper's aggressive leadership Petro-Canada moved quickly and acquired Atlantic Richfield Canada for $340 million (ARCO needed cash to develop Prudhoe). This purchase gave Petro-Canada producing as well as exploratory property. The day before the Alaska delegation interviewed Mr. Hopper, Petro-Canada purchased control of Pacific Petroleum Company - a major oil and gas producer and refiner which also owned a 33% equity position in Westcoast Transmission Company.

Such actions by a federal oil company in Canada caused some expression of concern by Petro-Canada's private sector competitors. For the most part, however, Petro-Canada is looked upon as just another well managed oil company. Only some of her unique powers such as the right of first choice in the selection of unleased federal land, or a one quarter working right in unproductive leases - at no payment, upsets her private sector competitors. Petro-Canada however, continues to try to

improve its cash flow and looks forward soon to the day when it need no longer depend on the Federal Treasury in Ottawa.

Alberta Energy Company

Government participation in energy development in Canada exists in a variety of forms of company ownership and control. The Alberta Energy Company is 50% owned by the Province of Alberta and 50% owned by small Canadian shareholders. The Company owns oil and gas development leases, a synthetic crude pipeline, a coal mine, and is also proposing the mixed SNG - petrochemical project discussed earlier. This Company is three years old and has 200 employees - not large by petroleum company standards. However, Alberta Energy Company believes in starting slowly in new areas until it has acquired expertise. In its petrochemical project, for example, it intends to take a minority interest while developing both management and technical ability.

Trans-Canada

Trans-Canada Pipeline Company is today a privately owned regulated utility expecting to make a profit and pay taxes. However, in the late 1950's when Trans-Canada was still a project in search of financial backing the federal government was required to step in and own the segment of the system crossing northern Ontario in order to get the rest of the line financed. That action was the successful catalyst for the project which, once in operation, generated sufficient cash flow to pay

AGO 532791

back the Canadian government for its ownership share and return the system entirely to private hands.

Summary

The experiences of Canada with government participation in energy development are not necessarily transferrable. After all, Canada has a long history of government participation in major projects. Nevertheless, the government energy companies in Canada do seem to be making reasonable progress toward their objectives and may provide real benefits in the future.

AGO 532792

[1] We have entered into agreement with Dr. Todd Doscher for him to continue his reservoir consulting services to the Legislature. Currently Dr. Doscher is working about three days a month with the state's reservoir modeling contractor, H.K. Poolen & Associates Inc., on the three dimensional reservoir engineering model. The results of this modeling study will be extremely important since they will resolve many of the uncertainties surrounding the possible loss of oil as a consequence of gas production, and the arguments over whether or not water injection should be initiated at an early date. We have been following the development of this model very closely, and believe that it is currently on schedule with the first runs to be available in early February. While additional studies will be required after that date, and possible later rearrangements made in the reservoir model, the February results should be definitive enough to provide the essential policy guidance to the Legislature, and to the Alaska Oil and Gas Conservation Commission as it sets reservoir management policy.

[2] One of the largest benefits from the completion of the natural gas pipeline facility will almost certainly be the royalty and tax revenues that will be generated by sale of the gas. However, it is particularly impossible to quantify these benefits until the natural gas pricing situation is resolved, and producers' sales contracts have been agreed upon. We are continuing to follow the pricing proposals, and FERC deliberations on these points. When the necessary input information is available we will be prepared to almost immediately produce the necessary revenue estimates with our oil and gas severence tax and royalty income model.

[3] Because of the many uncertainties surrounding the gas pipeline issues, it is almost certain that this matter will be before the legislature for some time. We would propose that $46,000 be reserved for further consulting studies and other work or travel which may be required during the 1979 legislative session.

Appendix C

PROPOSED BUDGET ALLOCATIONS

In mid May of this year, the free conference committee on the budget requested an analysis of the funds and work that would be necessary to deal with the natural gas pipeline issues. A May 18th memo to the free conference committee (Attachment C) recommended that $345,000 be appropriated for this purpose. This sum was subsequently appropriated to the Research Division, Legislative Affairs Agency, for the purpose of studying the costs associated with "direct financial participation by the state and (sic) Northwest Alaska Pipeline Project" (FCC Report - General Government Operating, p. 190).

In addition to this amount, Ch. 163 SLA 1978 (FCCS SCS CSHB 920, p. 24) made an additional special appropriation of $130,000 to the Research Division "for studies related to direct financial participation for (sic) the natural gas pipeline project."

The proposed budget is as follows:

Studies and Activities Related to Direct State
Participation In The Northwest Pipeline Project
(see Attachment B for description of studies)

Funds Available:

Budget Appropriation to LAA, Research	$345,000
Special Appropriation to LAA, Research	$130,000
Total Funds Available-	$475,000

Proposed Expenditures:

Gas Marketability/Pipeline Financing Study	$ 85,000
Equity Options Analysis	$ 22,000
Portfolio Concentration Analysis	$ 50,000
Study of Gas Reinjection Economics	$ 29,000
Economic and Fiscal Impact of Project (Economic Modeling $38,000; Technical Symposium $5,000)	$ 43,000
Proprietary/Regulatory Conflict of Interest Study	$ 20,000
National Political Impacts	$ 20,000
Reservoir Engineering Consulting Services (already contracted)1	$ 20,000
Production Revenue Study2	-0-
Travel, Per Diem, Meeting Expenses	$ 10,000
Reserves for Contingencies and Expenditures During 1979 Legislative Session3	$ 46,000
Total Proposed Expenditures	$345,000
Funds Not Allocated Under This Budget	$130,000

Fiscal Year 1979

NORTHWEST PIPELINE - 203

PERSONAL SERVICES

	Salary		
Randall Hoen	$8,404.82	July-December Total	$8,404.82

TRAVEL

	Travel	Per Diem	Encumbrances
Gregg Erickson	$2,115.80	$848.57	
Larry Eppenbach	1,677.79	1,355.33	
Alexander Hoke	171.16	226.87	
Rep. Gardiner	1,748.53	825.00	
Rep. Chatterton	1,137.89	508.67	
Rep. Miles	964.76	835.00	
Sen. Colletta	372.28	70.00	
Sen. Sumner	543.44	35.00	
Sen. Ferguson	372.28		$ 372.28
Rep. Cotten	964.76	715.00	
Kay Brown	213.06	213.05	
Avis Rent-z-Car	104.70		
Rep. Bennett	102.12		
Cheryl Frasca	171.16		
Judy Dillard	171.16		
Sen. Sackett	373.22		
		July-December Total	$16,465.20

CONTRACTUAL

	Expenditures	Encumbrances
Doschers Group	$ 1,994.52	$ 18,005.48
ISER (Gas Marketing)	27,261.03	57,738.97
Fosters Associates	520.00	
Postage	.45	
Juneau & Douglas Telephone	481.23	
Print Shop	498.00	
Birch, Horton, Bittner, Monroe	4,865.74	30,134.26
ISER (Symposium)	4,283.00	

(Continued)

AGO 532796

A

NORTHWEST PIPELINE - 203

Fiscal Year 1979

CONTRACTUAL (Cont)

	Expenditures	Encumbrances		
Mason Gaffney	$ 832.16	$		
Matthew Berman	706.48			
David Kresge	1,403.56			
Alaska Airlines	36.27			
The Golden Lion	226.05			
Miner Publishing	23.00			
Color Art Printing	136.40			
Douglas Pope	1,654.40	3,345.60		
Proposed (White Weld)		125,000.00		
Proposed (Reservoir Study)		60,000.00		
Kelso Associates		25,000.00		
			July-December Total	$364,146.60

COMMODITIES

	Expenditures			
Arctic Office Machines	$ 6.15			
			July-December Total	$ 6.15

BUDGET	$475,000.00
Total Expenditures and Encumbrances	(389,022.77)
BALANCE 12/31/78	$ 85,977.23

AGO 5327796 B.

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES

REP. BILL MILES, CO-CHAIRMAN
REP. C.V. CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR

EX-OFFICIO MEMBERS
MR. ROBERT LTRESCHE
MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

To: George Hohman, Chairman
Legislative Council

From: Bill Miles, Co-chairman
Mike Colletta, Co-chairman
Joint Gas Pipeline Committee

Date: January 30, 1980

Re: Interim Report

Attached is the Interim Report for the Joint Gas Pipeline Committee. If you have any questions, we will be happy to answer them.

The Committee would like to recognize the outstanding work of Research Assistant, Mary Halloran, in compilation of this report and in interim service to the Committee.

AGO 532797

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES
REP. BILL MILES, CO-CHAIRMAN
REP. C.V. CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

INTERIM REPORT

Joint Gas Pipeline Committee
Alaska State Legislature

January 30, 1980

Through passage of SCR 33, the Joint Gas Pipeline Committee was charged with monitoring the progress of the Northwest Alaska gas pipeline project, and continuing its study of possible financial participation by the state. This report reviews the activities of the Committee through the interim, reports received by the Committee, and the status of issues affecting the progress of the pipeline project.

COMMITTEE ACTIVITIES

June 4 Meeting

At its first formal meeting June 4, the Committee organized the work for the interim. The Committee asked for a report on the sufficiency of state general revenues for a possible direct cash investment in the project. It also agreed to work with the Department of Revenue to obtain bond counsel opinion on the legality of using state general obligation bonds to finance state equity participation in the project.

AGO 532798

The Committee requested a report on the possibility of federal participation in the project financing, and approved a $15,000 contract with the Arctic Environmental Information and Data Center (AEIDC). AEIDC was to investigate the unresolved technical issues affecting pipeline construction. The Committee agreed to work with the state administration and Northwest Alaska Pipeline Company to study the conditioning and processing issues related to the pipeline (See Appendix A for more information on interim activities through October 10, 1979).

November 21 Meeting

At its second formal meeting the Committee took the following actions:

1) Approved a resolution concerning Alaska's securing gas liquids for use in an Alaska petrochemical industry (see Appendix D);

2) Endorsed a proposed schedule for administration action for acquisiton and delivery of gas liquids, and development of a related industry (See Appendix E);

3) Endorsed a proposal for study of instate use of natural gas for residential and commercial needs, and expansion of existing industry, and for identification of new instate markets. The Committee has requested that the Legislative Council release funds appropriated for this purpose;

4) Ratified an extension of the existing contract between the Committee and the Doschers Group. The contract is

AGO 532799

extended until June 30, 1980;

5) Ratified a contract between the Committee and the law firm of Birch, Horton, Bittner and Monroe. The $25,000 contract is for legal and consulting services.

Merger with the Governor's Blue Ribbon Working Group on Gas Conditioning

The Committee co-chairmen, Sen. Mike Colletta and Rep. Bill Miles, served on the Governor's Blue Ribbon Working Group on the Gas Conditioning Plant. After a series of meetings focused on the gas conditioning plant and the viability of future instate use of Prudhoe Bay natural gas and/or gas liquids, the Governor's Working Group resolved the following:

1) the subcommittee's reports, as approved by the full Working Group, be transmitted to the Governor as the preliminary report;

2) the Governor be requested to determine the present-day feasibility of an instate petrochemical industry, particularly by actively contacting and soliciting the interest of major petrochemical companies with regard to the feasibility of such development; and

3) the Governor be requested to preserve the State's options by requesting the Federal Energy Regulatory Commission to re-open for hearing the project's size and pressure issue and, failing that, filing an appeal of the FERC size and pressure order in federal court no later than October 5, 1979. The Working Group's September 21 resolution was by another asking the Governor to continue the Working Group,

AGO 532800

by allowing its members to serve as ex officio members of the Legislature's Joint Interim Gas Pipeline Committee.

Other Activities

Committee members have had informal discussions about the project with the Federal Inspector for the Pipeline, John Rhett; Canadian Pipeline Commissioner, Mitchell Sharp; and Northwest Energy president John McMillian.

Rep. Miles and House members, Speaker Terry Gardiner and Rep. Sam Cotten, traveled to New York and Washington D.C. to discuss the project with major Wall Street investment firms, members of the Federal Energy Regulatory Commission, and White House and Congressional staff in May. Sen. Colletta and Don Wold of the Alaska Royalty Oil and Gas Development Advisory Board traveled to Tulsa, Oklahoma, and Houston, Texas, to investigate the interest of petrochemical firms in gasline-connected petrochemical development in Alaska.

In November, Rep. Miles, Sen. Colletta, Sen. John Sackett and members of the administration met with North Slope gas producers, petrochemical firms, Northwest's investment advisors, and the federal government concerning the gas pipeline project. Rep. Miles presented a report on this fact-finding trip at the November 21 meeting of the Committee (See Appendix C).

REPORTS RECEIVED

The Committee has received much informal and formal information about the many aspects of the gas pipeline project. The

AGO 532801

Committee's "Mid-Interim Report" (see Appendix A) reviewed many of those reports, including the IROR order; constitutionality of using state general obligation bonds for project equity participation; bonding authority status; availability of state funds for investment in the project; federal assistance to the gas pipeline; Northwest's stance toward state participation in the gas pipeline; West Coast oil surplus; producer benefits and policy evaluation model; and progress reports by the Doschers Group, H. K. Van Poollen and Associates, and the Arctic Environmental Information and Data Center.

An October 26 "Gasline Update" (see Appendix B) reviewed other material, including reports on the bonding authority; status of technology; instate use of North Slope natural gas; and gas sales. The November 21 Committee report (see Appendix C) reviewed the following: gas pipeline fact-finding trip; administration plans for promotion of petrochemical options; alternatives for state participation in gas pipeline financing; state-initiated law suit status and current FERC proceedings; federal perspective on the project; activities of the State Pipeline Coordinator's Office; and an update on the Prudhoe Bay reservoir model studies.

UNRESOLVED ISSUES

National and international perspectives

On the national and international level a number of still unresolved issues are affecting the progress of the gas pipeline project. They include both regulatory and financial aspects of the project, such as Canadian gas exports and

AGO 532802

prebuilding; responsibility for conditioning costs; preliminary financing for the necessary engineering design; project financing, especially overrrun guarantees and federal backstopping; marketability; expansion of the Northwest partnership; producer participation in the project; and resolution of proximity and liability problems. That national interest is focused on these problems is evident both through the statements and actions of President Jimmy Carter and the federal government; and the activities of the congressional committees.

State perspective

From the state perspective a number of still unresolved issues remain. They include possible affects of the project on the state and its residents, and possible state actions affecting the project. Among these are the effect of gas withdrawals on ultimate oil recovery; provisions for resident hire; options for petrochemical development, including the availability of gas liquids; instate use of natural gas for community and industrial needs; possible state participation in financing; state right-of-way stipulations; and expected revenues to the state.

RECOMMENDATIONS

Given the number of unresolved state and federal issues critical to the success of the gas pipeline project, the Committee can not at this time make a judicious recommendation

AGO 532803

about the advisability and feasibility of state financial investment in the project. The Committee expects to continue its task of monitoring the project with the aim of protecting and promoting the State's interests. Therefore, it is the co-chairmen's recommendation that it be extended as a formal joint committee for a period to be determined to carry out the purpose and intent of Legislative Resolve No. 33.

Mike Colletta

Senator Mike Colletta
Co-Chairman

Bill Miles

Representative Bill Miles
Co-Chairman

Joint Gas Pipeline Committee
January 30, 1980

AOO 532804

APPENDICES

APPENDIX A - "Mid-Interim Report: Joint Gas Pipeline Committee, Alaska State Legislature: October 10, 1979"

APPENDIX B - "Gas Pipeline Update; October 26, 1979"

APPENDIX C - "Report on Joint Gas Pipeline Committee Meeting; November 21, 1979"

APPENDIX D - "Resolution"

APPENDIX E - "Proposed Gas Liquids Program Schedule"

AGO 532805

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES
REP. BILL MILES, CO-CHAIRMAN
REP. C.V. CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

November 21, 1979

RESOLUTION

WHEREAS, development of an economic and environmentally sound petrochemical industry in Alaska would be in the State's best interest through provision of longterm jobs, a stable tax base, and related benefits;

WHEREAS, gas liquids, including ethane, are the most viable feedstock for a petrochemical industry;

WHEREAS, Alaskans wish to receive "add-on" value from development of the State's natural resources, avoiding repetition of "boom and bust" economic cycles created by shortterm, large scale construction projects;

WHEREAS, petrochemical development in Alaska is not tied to State financial participation in the gas pipeline project, but such participation could assist the gas transmission system;

BE IT RESOLVED that the Joint Gas Pipeline Committee and the Governor's Task Force urge the Governor, the Legislature, Northwest Alaska Pipeline Company, the Federal Government, and the petroleum industry to vigorously work towards securing gas liquids for use in an Alaska petrochemical industry; and

FURTHER RESOLVED that the Governor, in cooperation with the Legislature and local governments, contact and solicit the interest of major petrochemical companies with regard to such an industry being located in the State; and

FURTHER RESOLVED that unless gas liquids, including ethane, are guaranteed to be available for maximum instate use and processing, the State should not participate in financing the gas transmission system.

Endorsed by the Governor's Task Force on Gas Conditioning
November 21, 1979

AGO 532806

PROPOSED GAS LIQUIDS PROGRAM SCHEDULE

Date

11-26-79 — Gas Liquids Committee - formation Committee prepare State Policy for Economic Development

11-26-79 — Acquisition of Gas Liquids - State and Federal governments negotiate with producers to acquire 2 year option on gas liquids available to justify system.

Conditioning Plant-Liquids Extraction - Coincide with acquisition of liquids - work with producers, pipeline company, and federal government regarding design and location.

1. Program for Gas Liquids Delivery System - Arrange for delivery of gas liquids from conditioning and/or extraction plant to potential industrial sites.

   12-3-79 Solicitation letters to companies.
   1-15-80 Deadline for "Letters of Interest". Adoption of Criteria for proceeding.
   2-1-80 Selection of successful company(s).
   6-1-80 Completion of feasibility study.

2. Program for Development of Industry - Development of those projects that can be created utilizing gas liquids as resources - i.e. petrochemical industry.

   12-3-79 Solicitation to companies.
   1-15-80 Deadline for "Letters of Interest".
   2-1-80 Adoption of Criteria for proceeding. Selection of "Qualified Companies".
   11-1-80 Completion of feasibility work.
   12-1-80 Selection of developing company.

3. Preparation of Necessary Contracts - Those contracts necessary to execute the entire program.

   1-1-80 Agreement between State, producers, and gas pipeline company for two year option to acquire necessary gas liquids. Contract for Sale of Prudhoe Bay royalty gas to a developing company.

   2-1-80 Agreement between State, producers, and

developing company to exchange royalty share of methane for additional producer's liquids.

3-1-80 Agreement between State, producers, and developing company to acquire additional gas liquids from producers sufficient to justify delivery system.

12-1-80 Finalize all contracts.

4. Special Programs

1-1-80 Identify need for and draft special legislation which may be required - Tax programs and/or various incentives.

3-1-80 Deliver reports to Legislature.

AGO 532808

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES
REP. BILL MILES, CO-CHAIRMAN
REP. C.V. CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

ACTIONS OF THE JOINT GAS PIPELINE COMMITTEE
November 21, 1979

A page detailing Committee actions at the Joint Gas Pipeline Committee meeting November 21, 1979, was inadvertently left off the original Committee report. The following actions were taken by the Joint Gas Pipeline Committee:

(1) A resolution concerning Alaska's securing gas liquids for use in an Alaska petrochemical industry was adopted (copy attached).

(2) A proposed schedule for acquisition and delivery of gas liquids, and development of a related industry was endorsed as a suggested timetable for Administrative action.

(3) A proposal for study of instate use of natural gas for residential and commercial needs, and expansion of existing industry, and identification of new instate markets was endorsed. The Committee will request that the Legislative Council release funds appropriated for this purpose.

(4) An extension of the existing contract between the Committee and the Doschers Group was okayed. The Contract will be extended to June 30, 1980; the contractual amount, however, remains the same.

(5) A contract between the Committee and the law firm of Birch, Horton, Bittner and Monroe was ratified. The $25,000 contract is for legal and consulting services.

AGO 532809

participation in the gas pipeline project. One, they support maximum instate use of gas liquids. Two, they believe acquisition of liquids is the only basis for state financing of the gas pipeline. And, third, they urge the State to take the lead in purchase negotiations of the producers' liquids, not to rely on the federal government to broker the deal.

Resolution

The following resolution was endorsed by the Governor's Task Force on Gas Conditioning November 21, and later approved by a majority of the Joint Gas Pipeline Committee.

RESOLUTION

AGO 532810

Charles Behlke, State Pipeline Coordinator

Behlke expressed his concern that politics and federal pressure may lead to bad technical decisions on the project. He added, however, that the State and the federal agencies are working well together in technical groups, and that the State is working pretty well with Northwest. Behlke discussed some of the technical problems, such as frost heave, proximity, and overlapping state regulations. He urged legislators to examine the past legislation calling for local hire. The State right-of-way lease will probably consider the resident hire issue; its provisions will have to be congruent with the U.S. Supreme Court decision on the issue.

Behlke also drew the committee's attention to the fact that construction of a liquids line along side the gas pipeline presents many problems. To construct a liquids line in addition to the main gas line makes enough difference that it could delay the Northwest main line.

Hoyle Hamilton, Alaska Oil & Gas Conservation Commission

Hamilton reported on the ongoing Prudhoe Bay reservoir model studies. The study results, expected in December, will form the basis for the Conservation Commission continuing or revising its Order 145 setting the gas and oil offtake rates.

OTHER ACTIONS

Mayors' Position

The four Alaska mayors on the Governor's Task Force stated their position on potential petrochemical development and State

AGO 532811

involved in the project, trying "to move everyone along together." The main emphasis of the recent discussions has been the Exxon financing proposal.

Exxon proposes that the producers furnish 40% of the debt and 40% of the equity financing to completion of the project. The conditioning plant is to be considered as a part of the transmission system under the Exxon proposal. Exxon also wants a change in the Northwest partnership so that issues are decided by a two thirds (2/3) vote, not a simple majority, effectively giving the producers a veto over all management decisions.

The federal government's response has been to discuss the Exxon proposal with the Department of Justice and other participants. Justice finds the proposal "unacceptable," because of the issues of producer control and competition. However, Justice did say that producer participation in the project is likely. Haas says DOE is developing an alternative proposal which will be available for discussion in a couple of weeks.

Discussion between Committee members and Haas covered a number of points: definition of an "all events" tariff, tracking, the Federal viewpoint on the State's role in the project, and the importance of gas liquids to the State. Haas said that the Dept. of Energy would help the State obtain access to the gas liquids. In the discussion of potential state investment in the gas pipeline system, Haas listed three possibilities: conditioning plant ownership; equity investment; and overruns guarantees "where many people believe it's needed most."

AGO 532812

the CO2 standard issue and completion of the Environmental Impact Statement. If FERC loses the law suit, the Commission will have to take a comprehensive look at the interrelated issues of pipeline pressure, CO2 standard, liquids carrying capacity, and conditioning plant location. However, Loeffler said, the limited judicial review process available under the Alaska Natural Gas Transportation System.Act may hinder the State's chances to overturn the prior FERC order.

Loeffler also commented on other issues under FERC consideration, including conditioning costs and prebuilding. FERC is staying its order on conditioning costs until December 5, at the request of U.S. Energy Secretary Duncan. The stay on the order has kept the producers and the State from filing suit on Order 45 which would place the entire responsibility for paying conditioning costs on the gas producers. On the prebuilding issue, FERC is waiting on a decision by the Canadian National Energy Board on export applications for Canadian gas. The export decisions are expected by early December; FERC may decide on the prebuilding applications for the gas pipeline's Western leg by January.

Jerry Haas, U.S. Department of Energy

The Federal Government wants conditional commitments for financing in place soon so that the engineering design can be completed and assurances provided to Canada that will move the prebuilding ahead. The Department of Energy has initiated discussions with the many parties

AGO 532813

5

Arlon Tussing, Economic Consultant

Tussing reported on another financing alternative open to the State: underwriting the sale of public stock in the project to individual Alaskans. The State would underwrite and finance sales of shares in the pipeline directly to Alaskan citizens. The rate of return to equity investors will be 30% after taxes, said Tussing (17.5% centerpoint rate of return, plus 10% investment tax credit). Those benefits could be passed directly to Alaska citizens in a "supremely secure" investment if the pipeline is built. The State would advance funds to a public partnership in the form of a loan, later converted to shares in the pipeline itself. The State would sell $100 warrants, later convertible to stocks, to individuals. This financing approach would give the State a voice in pipeline management during construction, although the State would not hold a permanent equity share. The proposal applies only to the equity portion of the Alaska segment, that is, to 25% of $5-7 billion, or $1.25-1.75 billion.

The approach could also be used to finance the conditioning plant, provided it has a rate of return similar to the pipeline itself.

Bob Loeffler, State's Counsel in D.C.

Loeffler reported on the status of the State's suit appealing the FERC order on pipeline size and pressure. The U.S. District Court of Appeals has to decide by January 3 whether to overturn the August 6 FERC order. In the meantime, FERC has stopped consideration of

AGO 532814

on instate use of royalty gas; those companies which submit proposals will have the right to compete for the royalty gas. At the end of six months, a selection of the best company will be made, with that company to get the State's options (if any) on liquids. (For more information, see the Proposed Gas Liquids Program Schedule attached to this report).

Peter Lewes, Lazard Freres

Lewes, a consultant to the Gas Pipeline Committee, reported on four alternatives for state financial participation in the gas pipeline project: (1) state ownership of the conditioning plant; (2) tax exempt bonds up to $1 billion; (3) insurance fund for overruns; and (4) equity participation in the pipeline itself. Lazard Freres prefers the option of state ownership of the conditioning plant. This option gives the State leverage as the conditioning plant is essential to the entire project. The State does not have to run the plant, but should hold title.

The conditioning plant could probably be financed by tax-exempt bonds; the debt would be non-recourse financing in which the State would not be liable for the debt. The rate of return, estimated Lewes, should be about 17.5%, the same as the pipeline incentive rate of return. This option is low risk, with high rewards, yielding more to Alaska than the other financing options. (Lazard Freres' comments were presented in greater detail in a written statement to Attorney General Av Gross November 20, 1979.)

AGO 532815

business from that demonstrated during the Alpetco contract negotiations.

Discussions with investment firms representing Northwest covered financing and instate use of liquids. The Northwest group opposes federal financial participation, but calls Alaska participation both necessary and desirable.

Northwest approves of the Exxon proposal for financing, but wants the emphasis shifted from equity participation to overrun guarantees. Northwest now wants both the producers and Alaska to guarantee cost overruns. The group will support Alaska's bid for gas liquids.

Federal government representatives were firm in their opposition to federal financial participation in the gas pipeline project, but said that Alaska participation is needed. The Exxon proposal was regarded as a first step, but one which needs changes. The federal representatives focused on cost overruns as one of the biggest problems facing the project. They strongly support and would help the State to acquire gas liquids.

Av Gross, Attorney General

Attorney General Gross spoke of the Administration's plans for promotion of petrochemical options and sale of Alaska's royalty gas. The Department of Natural Resources will "presubmit" a royalty gas sales contract for tentative approval by the Legislature this session; the contract will include a State option to purchase the liquids. At the same time, Gross said, the State will ask for formal proposals

AGO 532816

PRESENTATIONS

Rep. Miles, Sen. Colletta, Sen. Sackett, Attorney General Av Gross, and Revenue Commissioner Tom Williams recently met with North Slope gas producers, petrochemical firms, Northwest's investment advisors, and the federal government concerning the gas pipeline project. Miles reviewed the information gathered on that trip.

Talks with producers (Exxon, Arco and Sohio) centered on six points: (1) Producer attitudes toward federal participation in gas pipeline financing are mixed; some feel that such participation will be necessary, others feel that it will not be necessary if certain other items fall into place; (2) Alaska participation, say the producers, is not necessary, although it may be helpful from a "psychological" point of view; (3) $200-300 million is needed to complete the project engineering design; (4) Producers are willing to negotiate to make gas liquids available to the State of Alaska; (5) Producers generally support the recently announced Exxon proposal concerning producer participation in the project; and (6) The Exxon financing proposal does include provisions for cost overruns during project construction.

Discussions with petrochemical firms centered on three areas: feasibility, problems and recommendations. Feasibility for petrochemical development in Alaska is good, said the firms. The problems, however, are fourfold: state and federal government actions and attitudes; environmental concerns; feedstock security; and cost. The firms recommended that the State secure the liquids, have a detailed feasibility plan developed, and change its way of doing

AGO 532817

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES
REP. BILL MILES, CO-CHAIRMAN
REP. C.V. CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

REPORT ON

JOINT GAS PIPELINE COMMITTEE

MEETING

November 21, 1979

The Joint Gas Pipeline Committee met November 21, 1979, in Anchorage. Meeting with the legislative committee were members of the Governor's Task Force on Gas Conditioning.

Presentations included the following:

Rep. Bill Miles, Chairman	Gas Pipeline Fact-finding Trip
Av Gross, Attorney General	Administration's preparations for sale of State's royalty gas
Peter Lewes, Lazard Freres	Alternatives for State participation in gas pipeline financing
Arlon Tussing, Economic Consultant	Alternative for Alaska participation in gas pipeline financing
Bob Loeffler, State's Counsel in D.C.	State law suit status and current FERC proceedings
Jerry Haas, U.S. Dept. of Energy	Federal perspective on gas pipeline project
Chuck Behlke, State Pipeline Coordinator	Activities of State Pipeline Coordinator's Office
Hoyle Hamilton, Alaska Oil & Gas Conservation Commission	Prudhoe Bay reservoir model studies update

AGO 532818

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN — REP. BILL MILES, CO-CHAIRMAN
SEN. FRANK FERGUSON — REP. C.V. CHATTERTON
SEN. BILL SUMNER — REP. TERRY GARDINER
REP. JOE HAYES — REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE — MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

MID-INTERIM REPORT

Joint Gas Pipeline Committee
Alaska State Legislature

October 10, 1979

INTRODUCTION	pp. 1-2
GAS PIPELINE FINANCING	pp. 2-16
Regulatory Issues	p. 3
Constitutionality of Using State General Obligation Bonds for Equity Participation	pp. 3-5
Bonding Authority	pp. 5-7
Availability of State Funds for Investment	p. 8
Federal Assistance to the Gas Pipeline	pp. 9-14
Northwest's Stance toward State Participation	pp. 14-16
OTHER REPORTS	pp. 17-25
West Coast Oil Surplus	pp. 17-20
Producer Benefits Model; Sadelrochit Formation, Prudhoe Bay Field: A Description of a Policy Evaluation Model	pp. 20-22

AGO 532819

The Doschers Group	pp. 22-23
H.K. Van Poollen and Associates	pp. 23-24
Arctic Environmental Information and Data Center	pp. 24-25
CONDITIONING PLANT	pp. 26-28
CURRENT CONTRACTS	pp. 28-29
A CLOSING NOTE	p. 30

AGO 532820

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES
REP. BILL MILES, CO-CHAIRMAN
REP. G.V. CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

MID-INTERIM REPORT

Joint Gas Pipeline Committee
Alaska State Legislature

October 10, 1979

The Joint Gas Pipeline Committee met formally June 4, 1979, in Anchorage to organize the Committee's work for the interim. (A report on that meeting is attached). Since that time Committee members have had informal discussions with the new Federal Inspector for the Pipeline, John Rhett; Canadian Pipeline Commissioner, Mitchell Sharp; and, on more than one occasion, Northwest Energy president, John McMillian.

The Committee co-chairmen, Sen. Mike Colletta and Rep. Bill Miles, served on the Governor's Blue Ribbon Working Group on the Gas Conditioning Plant for Prudhoe Bay Gas. In addition, Rep. Miles and House members, Speaker Terry Gardiner and Rep. Sam Cotten, traveled to New York and D.C. to discuss the gas pipeline project with major Wall Street investment firms, members of the Federal Energy Regulatory Commission (FERC), and White House and Congressional staff.

AGO 532821

Recently Sen. Colletta and Don Wold of the Alaska Royalty Oil and Gas Development Advisory Board traveled to Tulsa, Oklahoma, and Houston, Texas, to investigate the interest of major petrochemical firms in gasline-connected petrochemical development in Alaska.

Members of the Committee have worked extensively on gasline-related issues through other forums. A two-day hearing on the management of the Prudhoe Bay reservoir was held by the House Resources Committee, under the direction of Co-chairman Miles, during the August Special Session. Several Committee members, as well as other legislators, presented testimony at the September 4-6 FERC hearings on the Draft Environmental Impact Statement for the gas conditioning plant and pipeline pressure issues.

GAS PIPELINE FINANCING

The Committee has received much informal and formal information on different aspects of the gas pipeline financing, and the State's options for participation in project financing. The following sections will review that information.

AGO 532822

1. Regulatory issues:

In a major ruling, the FERC issued a final Incentive Rate of Return (IROR) order September 6. The order sets a 17.5% rate of return as a centerpoint for equity investors in the Alaska and Northern Border segments of the project. The order, however, may be indirectly challenged in other FERC proceedings as it sets the framework for gas producers to pay gas conditioning costs, an item of strong contention. Another still unresolved tariff-related concern is tracking -- how to allocate costs to consumers and gas service companies for Canadian gas flowing in the pipeline system before the full system goes into operation. On the strength of the IROR and other favorable regulatory decisions, Northwest currently plans to have a financial plan in place by the end of this year and to talk with investment markets during the first quarter of next year.

2. Constitutionality of Using State General Obligation Bonds for Equity Participation in the Gas Pipeline

In a July 9, 1979, memorandum, State Bond Counsel Wohlforth and Flint confirmed the earlier conclusions of Billy Berrier, Director, Division of Legal Services, Legislative Affairs

AGO 532823

Agency. In brief, Wohlforth and Flint stated that the constitutionality of using State General Obligation bonds for equity participation in the gas pipeline would rest on two points:

> "First, the project so financed must constitute an asset of relatively permanent value; and, second, the issuer of the bonds must retain some legal interest in the project."

That legal interest, suggested Wohlforth and Flint, could be through a "tenancy in common, mortgage, deed of trust, or other security interest in the pipeline."

The memorandum made clear that the spinoff benefits of the pipeline construction and operation are not sufficient legal grounds to render General Obligation bonds constitutional.

> "Mere general improvement of public prosperity and welfare, and even removal of economic insecurity, while viewed as laudable purposes, do not in themselves constitute capital improvements."

After examination of the related court cases, Wohlforth and Flint concluded that investment of State General

AGO 532824

Obligation bonds could probably meet the "physical" requisites of the "capital improvements" restriction on such bonds. They added,

> "However, the state must acquire sufficient legal interest in the capital improvement to overcome the constitutional deficiencies set forth in Hixson. An investment by the state of bond proceeds in 'equity related securities' does not meet this test. The financing must be accompanied by some form of interest in the pipeline. Clearly, the interest would have to be equivalent in value to the amount of bond proceeds devoted to its acquisition."

3. Bonding Authority

In 1978, the State Legislature passed AS 44.55, establishing the Alaska Gas Pipeline Financing Authority, commonly referred to as the Bonding Authority. The Authority is a mechanism by which the State may issue up to $1 billion in tax-exempt bonds for construction of the gas pipeline.

Northwest Pipeline Company sought to have consideration of revisions in the Bonding Authority legislation placed on the August Special Session agenda. Although that step was not

AGO 532825

taken, consideration has been given to technical changes which may be needed to clarify the Authority's legal ability to issue bonds.

In a September 21, 1979, report to Revenue Commissioner Tom Williams, Director of the Bonding Authority, Attorney John Messenger outlined those technical changes. Messenger did not discuss, nor was he asked to review, the policy matters inherent in the financial and Alaska impact plan called for under AS 44.55.

In general, the possible technical changes Messenger reviewed include:

(1) clarification and broadening of the purposes for which bonds of the Authority may be issued;

(2) a. provision that legislative approval of the financing and Alaska impact plan (hereinafter referred to as the Plan) and legislative approval of bonds be contained in separate concurrent resolutions;

b. provision that legislative approval of the bonds may contain such limitations as the Legislature deems appropriate;

c. elimination of the requirement that bonds be issued and sold in accordance with the Plan;

AGO 532826

(3) revision of the statute sections dealing with refunding bonds so that confusion over the approval process for such bonds is eliminated;

(4) provision for amendments of the Plan after passage by the Authority of a resolution authorizing sale of the bonds;

(5) provision for approval of the Plan (or a conditional Plan) by concurrent resolution;

(6) addition of language excluding the Authority or its bonds from AS 37.10.085 which prohibits the State from lending its credit or borrowing money for the use of a corporation;

(7) revision of AS 44.55 to include certain requirements which would meet proposed IRS regulations concerning the Authority's ability to act "on behalf of" the State and thus to issue tax-exempt bonds;

(8) modification of the Legislative findings to support the conclusion that gas pipeline financing by the Authority is for a public purpose; and

(9) other minor textual changes.

Messenger is drafting legislation embodying these changes for consideration by the Administration and the Legislature.

AGO 532827

4. Availability of State Funds for Investment in the Gas Pipeline Project

In an August 3, 1979, memo, Fiscal Analyst Milt Barker, of the Legislative Finance Division, reviewed whether projected FY 80 State revenues would permit an appropriation of $500 million for a direct investment in the gas pipeline. Barker concluded sufficient funds do exist whether such an appropriation was paid over at once or drawn down over a period of time. He cautioned, however, that FY 80 receipts depend, in substantial part, on the results of pending litigation over the petroleum income tax.

The Legislative Finance Division did not analyze -- nor was it asked to do so -- the financial policy implications of a $500 million direct appropriation to the pipeline project or the economic opportunity costs to the State of taking that action. The Division has been asked to prepare -- and the Committee expects to receive shortly -- an analysis of all projected revenues, both direct and indirect, the State would obtain from the successful construction and operation of the gas pipeline.

AGO 532828

5. Federal Assistance to the Gas Pipeline

A July 27, 1979, report by the law firm of Birch, Horton, Bittner and Monroe examined current prospects for federal assistance to the gas pipeline. Prepared by attorney Joseph Chomski, with the assistance of Richard Haggart and Lisa Nelson, the report described possible forms of Federal financial participation as follows:

(1) Direct loans to the project;

(2) Loan guarantees for the project;

(3) Federal guarantee of the prices of the gas supplies;

(4) Federal guarantee of Federal government purchases of such gas supplies.

These forms of federal support could be possible through Congressional passage of President Carter's proposed Energy Security Corporation legislation.

The most likely form, Chomski concluded, is provision of loan guarantees for at least a portion of the pipeline project. The loan guarantees would be structured within the parameters proposed in the Energy Security Corporation legislation, the report suggested.

AGO 532829

Another "much more remote" possibility for federal assistance would be provision of purchase guarantees for some or all of the North Slope gas. Such an approach would involve a "subsidy loss to the Treasury," an alternative the report authors find "extremely unlikely."

Regardless of the form, the probability of federal financial assistance "has become quite likely." The report states,

> "Thus, in the event that the project fails to finance privately, as now seems likely based on numerous expressions from the financial and energy community, federal financial support would seem to be very likely in that federal assistance to the project would result in the easiest, least expensive (to the federal government), earliest, largest, and -- most importantly -- surest single increment to the nation's energy supply of any of the options available to the federal government."

Federal participation is unlikely to be forthcoming "until Northwest concedes that it cannot finance the line privately (as promised to Congress) and either directly or via the Administration requests federal assistance." Congressional

AGO 532830

feeling, the authors found, towards federal backstopping remains negative as does public support for such action. In addition, no evidence was found of a White House initiative to change its stated policy opposing federal financing for the project.

The report analyzed Northwest's reasons for not changing its position with regard to requesting federal assistance. The reasons are twofold:

(1) A Northwest request for federal assistance "will create major political problems for the project and for the existing project management."

> "Consequently, we believe one major motivating factor for Northwest's not throwing in the towel on the private financing approach at this time is the fact that they must appear to have foreclosed every reasonable alternative to federal assistance before they return to Congress."

(2) Northwest wants to establish a clear public record that any failure of private financing is not the fault of project sponsors but rather of the federal regulatory process, and perhaps also of the oil companies (the gas producers) and the State of Alaska.

AGO 532831

For a number of reasons, the report authors believe that provision of federal financial assistance to the project will not occur before spring 1980 and more likely in 1981.

In conclusion, the report suggests steps the State may take in support of federal financing and of the project in general:
(1) Provide Congress and senior Energy officials with information of positive State actions taken with respect to the project;
(2) Conduct private and frank discussions with Northwest officials about the need for federal assistance; and
(3) Take steps to protect the State's interests by positive action on Alaska's own program of financial assistance.

The need for eventual federal assistance to the project stated in the Chomski report was, in large part, substantiated by the findings of Rep. Miles from May visits with Wall Street investment firms, federal energy officials and White House and Congressional staff. In a June 18, 1979, memo, Miles reviewed several issues, including federal guarantees, Alaska's role, Canada's role, the Federal role, regulatory activity, conditioning plant, producer participation, expansion of the Northwest partnership, the El Paso proposal and future action. As that memo was distributed to all legislators, only brief

AGO 532832

mention of its contents will be made in this report.

Miles indicated that Wall Street firms believe that some form of federal financing for the project will probably be needed. In contrast, the federal officials stated that the Federal government's goal is still a "purely privately-financed project." Alaska's financial participation at this time was generally seen by Wall Street as a cosmetic or psychological gesture, but not as an action which would "make or break" the project. Such participation, however, was strongly encouraged by the federal officials.

According to Wall Street, the most necessary components needed by the project at this time are:

(1) producer participation;

(2) a reasonable attitude by regulatory agencies;

(3) Canadian-U.S. interaction, especially on the Eastern leg; and

(4) additional expenditures by the project sponsors for design, engineering and other technical work.

AGO 532833

The federal officials, Miles found, felt the four components vital to the project at this time are:

(1) producer participation;

(2) State of Alaska equity participation;

(3) an expanded Northwest partnership; and

(4) more aggressive assistance from the Federal administration.

In addition, federal officials predicted that the major regulatory issues, such as conditioning costs, rate of return, and pipeline pressure, would be both ruled on and litigated by this fall.

6. Northwest's Stance Toward State Participation in the Gas Pipeline

On August 29, 1979, John McMillian, Northwest president, sent letters to both President Jimmy Carter and Governor Jay Hammond about Northwest's "lack of success in obtaining financial commitments from the State of Alaska in a timely manner." To Hammond, McMillian wrote, "Therefore, we hereby withdraw the proposed financing plan and the other arrangements based thereon which we have with the State of Alaska."

AGO 532834

McMillian presented, however, two other financing concepts for the Governor's consideration:

(1) State participation in the entire project in relation to its 1/8th royalty gas,

> "The state could provide 1/8th of the debt permanent structure, 1/8th of the construction overrun contingency fund, and some acceptable form of completion guarantee;"

(2) Structure State participation on the basis of participation by the oil companies,

> "Another thought would be to wait and see what the final participation of the oil companies in the project will be and the state could then be expected to have a financing package similar to that of the oil companies."

In the letter to President Carter, McMillian stated that Northwest's original proposal to the State "is, as evidenced by two years of frustrating delays, evidently not acceptable to the State." He went on to say,

> "We have never been able to explain the concept of tax-exempt bonds to the legislative members.

AGO 532835

> Therefore, we are now suggesting another plan whereby the State participates in 1/8th of the debt structure, 1/8th of the construction overrun contingency fund, and some form of completion guarantee."

McMillian called the 1/8th concept "a fair and reasonable request," and asked Carter to make a request to Governor Hammond and Alaska for Alaska's participation in project financing. He concluded,

> "If, even after your recommendations, we are not successful in obtaining the State's help and participation in project financing, it may be necessary to consider special federal legislation which will ensure that the State does not retain all of the project benefits, such as intrastate use of Alaska gas for Alaskans, and a very favorable wellhead gas price, without sharing in the debt structure of the project."

In his remarks to an Anchorage gathering October 5, 1979, McMillian reiterated his withdrawal of Northwest's previous financial proposal ($1 billion in tax-exempt bonds and $500 million in equity from the State) and mentioned the 1/8th approach as Northwest's new concept for financing. Everything, said McMillian, is open to renegotiation.

AGO 532836

OTHER REPORTS

In addition to the above-mentioned reports on gas pipeline financing, the Committee has received several reports on related issues. Those reports are reviewed in this section.

1. Final Report, West Coast Oil Surplus by Arlon Tussing

In an August 20, 1979, memorandum economist Arlon Tussing submitted his final report on the West Coast oil surplus issue. Tussing was under contract to help develop a strategy to solve the problem of "loss of state royalties and production taxes caused by the high cost of shipping 'surplus' Prudhoe Bay crude oil to Gulf and East Coast markets."

The problem was "solved," so to speak, by the agreement of North Slope oil producers to pay state royalties on the basis of the federal ceiling price, as of July 1, 1979, regardless of the oil's destination or transportation cost. The producers will also pay production taxes at the same rate. "Hence, exports or exchanges can no longer improve the state's immediate royalty and tax position," said Tussing.

AGO 532837

The State's effort to negotiate and get federal approval for international exchanges of Prudhoe Bay royalty oil would have been stalled, in any case, by the Congressional adoption of restrictive amendments to the Export Administration Act. The U.S. Senate, for example, adopted the Riegel Amendment which will make any future exchanges of North Slope crude difficult. The "surplus" problem will resurface for the State when federal price ceilings on crude oil prices are removed. The decontrol of crude oil prices, now scheduled for June 30, 1981, will make the Prudhoe Bay wellhead price again a netback price, determined by the oil's market value, less transportation costs. Under those circumstances, the State's fiscal interests would again be served by exports or international exchanges (as long as North Slope crude cannot be delivered to the nearest markets on the West Coast).

Tussing assessed the State's efforts to date to liberalize federal export restrictions as follows:

(1) The efforts resulted in the Department of Energy conducting a formal study of the issue and DOE's ultimate position in favor of exports;

(2) The proposed PEMEX exchange allowed the State to explain its case to a national audience and to receive national editorial endorsement;

AGO 532838

(3) Meetings between Alaska and California officials gave Alaskans "better insight into both the economics and the politics of petroleum on the West Coast and nationally;"
(4) Sohio's active cooperation, essential to the PEMEX proposal, was not realized, and Sohio's termination of the PAC-TEX project created Congressional ill-will toward any future exchanges which might benefit Sohio;
(5) The efforts "clearly failed" in Congress and "we may have failed only for lack of trying." Administrative and legislative indecision over whether to launch a serious lobbying effort led to no campaign by default.

Tussing also reviewed related issues, such as the use of North Slope crude in West Coast refineries, refinery modifications and grassroots refineries on the West Coast, and West-to-East oil pipelines.

The California Energy Commission, Tussing indicated, is today concerned about California refineries' high dependence on North Slope crude. The Commission wants to reduce that dependence and have contingency plans to deal with a possible cutoff. A North Slope cutoff would cause California to suffer "noticeable shortages in about seven days, and would result in serious economic disruption within two weeks."

AGO 532839

The picture for West Coast refinery modification and grassroots refineries is more complex. The growing scarcity of light crudes calls for major modifications in refineries. But, the fact is that present US and West Coast refineries may "already have as much gasoline capacity as the industry will ever need." Contributing to investor uncertainty are unsteady federal policy with respect to future production standards for gasoline and other regulatory restrictions.

The West-to-East oil pipeline proposals are not economically competitive with expansion of existing midcontinental pipelines without supplies of additional overseas crude oil. Such additional foreign supplies have been ruled out by President Carter with an announced ceiling on imports set at the 1978 levels.

2. Producer Benefits Model; Sadelrochit Formation, Prudhoe Bay Field: A Description of a Policy Evaluation Model, by Lawrence Eppenbach

Through work begun with the Division of Legislative Research and completed under contract to the Department of Natural Resources, Eppenbach has set up a computer program series. The "Producer Benefits Model" evaluates Prudhoe Bay geological

AGO 532840

information along with the costs of alternative methods of developing the reservoir. Based on data prepared by H.K. Van Poollen and Associates and, to a limited extent, information provided by the field operators, the model can be used to "forecast state revenues and industry cash flows associated with alternative policy options. It also calculates the net present values of these future returns in order to compare the value of one policy option to another."

In addition, the series of computer programs allows the operator to set varying parameters for the analysis:
--whether to use constant dollars or to include the effect of inflation;
--how the producers expect to finance their capital expenditures;
--what future wellhead values are likely to be; and
--what discount rate should be used to calculate the net present values.

The model results should provide useful comparisons between one field development plan and another. It will also clarify any differences in economic incentives between the State and the industry. The scope of the model is limited, however,

AGO 532841

to the Sadelrochit formation and only to field economics. Also it does not examine the economics of gas liquids production. Although more basic data is needed before the model can begin producing useful results, the model is now operational. It is available through the Division of Minerals and Energy Management, Department of Natural Resources.

Eppenbach's report includes sample outputs and contains program listings.

3. Progress Reports - The Doschers Group

Dr. Todd Doscher provides the Committee with an ongoing written overview of the work of H.K. Van Poollen and Associates on the State's three-dimensional reservoir model of Prudhoe Bay. Based on his work to date, Dr. Doscher's central conclusion is "that gas sales should not be committed until the need for water injection to at least compensate for gas withdrawals is firmly established, and still not then."

Gas withdrawals should not take place, Doscher indicates, until sufficient Prudhoe Bay reservoir performance history can be accumulated so that the effects of such withdrawals can be adequately inferred.

AGO 532842

Other areas of concern to Doscher are Prudhoe Bay reservoir pressure maintenance, the "nebulous plans" of the operators with respect to water flooding, and the need for the State to assure the ultimate Prudhoe Bay oil recovery efficiency will be increased from the base 20% level to 40%. These and other concerns prompt Doscher to not only recommend no gas sales at this time, but to "express grave concern about increasing oil withdrawal rates."

Major technical problems in the three-dimensional work thus far have been "the assignment of permeabilities and the positioning of shale barriers in the model of the reservoir."

4. Progress Report - H.K. Van Poollen and Associates and the Alaska Oil and Gas Conservation Commission

H.K. Van Poollen and Associates, under the direction of the Alaska Oil and Gas Conservation Commission, are responsible for a three-dimensional reservoir simulator model of the Prudhoe Bay reservoir and its performance. The purpose of the study is threefold:

(1) should there be gas sales or not, and, if so, how much;

AGO 532843

(2) should pressure maintenance be employed, and if so, how much; and

(3) are the field oil and gax maximum production rates allowed under Oil and Gas Conservation Order 145 still valid.

Confirming match runs between the earlier two-dimensional computer model and the three-dimensional model are being run at this time, with comparison runs scheduled soon. These latter runs will look at ultimate oil recovery, with and without gas sales, and with and without water injection. A report is expected to be released by the end of this month on this work. Then, it is planned to do a series of "what if" runs which will explore questions such as the effect of rate of production on ultimate oil recovery. A report on these latter findings is expected by the end of November.

5. Progress Reports - Arctic Environmental Information and Data Center (AEIDC)

The AEIDC is collecting information on the status of technical, environmental and other matters relating to the pipeline project.

AGO 532844

Under AEIDC review are the right-of-way and proximity issues affecting the design and construction schedule of the project. The materials submitted with the AEIDC reports to date indicate that many specific technical issues still require resolution prior to a final right-of-way decision by the Department of Interior. One major concern is the risk to the TAPS oil line from building the gas pipeline in close proximity.

Another technical issue is the lack of definitive data on how the project sponsors will handle the problems of pipeline construction and operation in permafrost soils. Other issues include liability of TAPS owners with respect to joint use of the right-of-way, mitigation of impacts to fish and wildlife, and minimization of gas pipeline crossings with the TAPS oil line and the North Slope haul road.

A full report will be prepared by the AEIDC by October 15, 1979.

AGO 532845

CONDITIONING PLANT

An issue which generated considerable discussion has been FERC's August 6, 1979, pipeline pressure order, its impact on the eventual location of the gas conditioning plant for the project and its effects on the viability of future instate use of North Slope natural gas. Also at issue are the conclusions and much of the content of FERC's Draft Environmental Impact Statement released July 27, 1979.

In response to widespread concern, Governor Jay Hammond appointed a Working Group on the Gas Conditioning Plant. The group's members included Sen. Colletta and Rep. Miles as well as administrative officials who are ex officio members of the Joint Gas Pipeline Committee. During September subcommittees of the Working Group met in several sessions to review the following:

(1) the State's progress to date in the FERC proceedings;

(2) benefits and costs of locating the conditioning plant in the Interior instead of Prudhoe Bay;

(3) alternatives for instate use of Prudhoe Bay natural gas and/or natural gas liquids;

AGO 532846

(4) the likelihood that the State would prevail in an appeal of the FERC size and pressure order; and

(5) the effects on the gas pipeline project -- especially in terms of delay -- if the State were to appeal the FERC size and pressure order.

Based on its review of these items, the Governor's Working Group made several findings and resolved the following:

(1) the subcommittees' reports, approved by the full Working Group, be transmitted to the Governor as the preliminary report of the Working Group;

(2) the Governor be requested to determine the present-day feasibility of an instate petrochemical industry, particularly by actively contacting and soliciting the interest of major petrochemical companies with regard to the feasibility of such development; and

(3) the Governor be requested to preserve the State's options by requesting FERC to re-open for hearing the size and pressure issue for the project and, failing that, filing an appeal of the FERC size and pressure order no later than October 5, 1979.

AGO 532847

The Working Group's September 21 resolution was accompanied by another asking the Governor to continue the Working Group, by allowing its members to serve as ex officio members of the Legislature's Joint Interim Gas Pipeline Committee.

CURRENT CONTRACTS

Many of the reports discussed earlier in this document were completed under FY 79 contracts. Currently, the Committee has the following firms and/or individuals under contract:

(1) The law firm of Birch, Horton, Bittner and Monroe - a $25,000 contract to provide written monthly reports on matters affecting approval and effectuation of the proposed gas pipeline. The contract runs September 1, 1979, through June 30, 1980. Project directors are Sen. Colletta and Rep. Miles;

(2) The Doschers Group - completion of an extended FY '79 contract for $20,000 which calls for Doscher to act as an independent technical advisor on matters related to oil and gas reservoir management policy. The contract ends December 31, 1979. Project director is Rep. Miles;

AGO 532848

(3) H.K. Van Poollen and Associates - completion of an extended FY '79 contract for $60,000 which calls for Van Poollen to develop a methodology for analyzing the development options of the Prudhoe Bay reservoir, i.e. the three-dimensional reservoir simulator computer model. The contract runs through December 31, 1979. The work is being carried out under the direction of the Alaska Oil and Gas Conservation Commission. Rep. Miles is the project director;

(4) Arctic Environmental Information and Data Center - a $15,000 contract to provide information on technical and environmental issues related to construction and operation of the gas pipeline. The AEIDC final report is due October 15, 1979. Rep. Chat Chatterton is the project director; and

(5) Lazard Freres - a $50,000 contract to provide analysis and examination of a possible State equity investment in the gas pipeline project. The contract ends June 30, 1980.

AGO 532849

A CLOSING NOTE

Copies of many of the documents mentioned in this report are available through the Legislative Library, Legislative Affairs Agency, Pouch Y, Juneau, Ak. 99811. All documents are also on file with the Joint Interim Gas Pipeline Committee, 727 N St., Suite 2, Anchorage, Ak. 99501. This report was prepared by Mary Halloran, Research Analyst, on behalf of the Joint Gas Pipeline Committee.

AGO 532850

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA
CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES

REP. BILL MILES
CO-CHAIRMAN
REP. C.V. CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR

EX-OFFICIO MEMBERS
R. ROBERT LERESCHE
MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4540

October 26, 1979

GAS PIPELINE UPDATE

The Joint Gas Pipeline Committee continues to receive much informal and formal information about the progress of the gas pipeline project. This paper reviews some of the information received since the publication of the Joint Gas Pipeline Committee's Mid-Interim Report on October 10, 1979.

GAS PIPELINE FINANCING

1. Report to the Bonding Authority by John Nuveen & Co.

In a September 24, 1979, letter to Bonding Authority Director Tom Williams, Nuveen Co. indicated that a $1 billion tax-exempt revenue bond issue could affect the State's general credit if it were accompanied by security features similar to the following:

(1) a full faith and credit guarantee of the State;

(2) a guarantee by the Permanent Fund;

(3) a "make up" provision to restore deficiencies in reserve accounts; or

(4) an obligation to issue or purchase completion bonds.

AGO 532851

With no such features and provided the bonds are secured by pipeline revenues and the financial resources of other participants, the revenue bond financing would not significantly affect the State's general credit.

However, Nuveen pointed out that if the State provided such additional security, impact on Alaska's credit would depend on the project's financial strength and "the extend to which other participants have assumed risks associated with the project." Those risks include: completion delays; cost overruns; start-up difficulties and failure to achieve design performance; casuality losses; and adverse political or regulatory decisions. "We understand that project participants have not at this time provided appropriate assurances regarding these risks," concluded Nuveen.

2. Report to the Bonding Authority by Dillon, Read & Co.

In a September 19, 1979, letter to Bonding Authority Director Tom Williams, Dillon & Read concluded that so long as the proposed $1 billion tax-exempt revenue bonds are "truly revenue bonds," they will have no adverse effect on the State's credit. "True" revenue bonds have no State sources pledged to repayment of the bonds; and revenues to service the bonds "will come strictly from funds generated from use of the project."

AGO 532852

Dillon & Read noted at least four conditions which need to be met to enable the Bonding Authority to issue and market revenue bonds:

(1) Passage of federal legislation providing for tax-exempt status for such bonds;

(2) Financing commitments for all other portions of the project, including the Canadian segment, in place;

(3) Agreement by a creditworthy entity either to pay off the bonds in the event the project is not completed, or, to provide the funds necessary for completion; and

(4) Existence of a reasonable expectation that project revenues would be sufficient to pay all operating costs and debt service, and provide a "reasonable margin" of revenues beyond the operating costs and debt service requirements.

TECHNICAL AND ENVIRONMENTAL ISSUES

1. "Status of Technology: Alaska Natural Gas Transportation System" by the Arctic Environmental Information and Data Center, October, 1979

In brief, the major technical issues remain unsettled, including the central issue of proximity of the gas pipeline to the TAPS oil pipeline. The lack of resolution will impact both the project's completion date and project sponsors' efforts to obtain financing.

AGO 532853

The lack of cooperative effort by the involved parties and the project's "sheer complexity" leave the identification of an alignment for the gas line unresolved, despite the Department of Interior's "provisional approval" last summer. "The potential for physical damage to TAPS during construction " remains a strong concern of TAPS owners.

On September 10, 1979, Northwest released an "Outline-Pipeline Design Process," an "extremely optimistic viewpoint." Upon examination of the proposed Northwest schedule and activities, the Arctic Environmental Information and Data Center (AEIDC) noted,

> "Northwest Alaskan is just now beginning to address some of the real problems that must be resolved before they receive approval on final design and begin construction...."

Thus, the projected 1984-85 completion date is "unrealistic." Instead, AEIDC estimates that the gas deliveries will be at least a year or two later than currently projected.
The lag in resolving technical problems will impact project financing:

> "Cost of the project cannot be determined with any certainty until the proximity question is resolved. Such factors as pipeline thickness, quantities of gravel required, construction schedules, and the question of liability between TAPS and ANGTS must also be resolved."

AGO 532854

The lag appears not to stem from disinterest in the technical questions on the part of Arctic scientists. Papers presented at the 30th Alaska Science Conference this fall dealt extensively with building a chilled gas pipeline in an arctic environment. The AEIDC comments,

> "The science and technology of construction and other factors of energy development in an arctic environment are certainly moving forward. The degree to which Northwest Alaskan is participating with the science and government community in this endeavor, however, appears to be minimal, at best."

The report reviews nine areas of current studies and testing: (1) burst tests; (2) blasting tests; (3) frost heave testing; (4) work pad considerations; (5) hydrology; (6) proximity to TAPS; (7) risk analysis; (8) design pressure; and (9) corrosion. Other administrative and political decisions may also impact the project's completion date. Three such upcoming items include: (1) GAO report on the economics and other matters; (2) reimbursement of costs for the permitting process; and (3) industry's planning and other work relating to the gas conditioning plant.

Gas pipeline planning to date "is fragmented and ill-planned, both by government and industry." The establishment of the office of Federal Inspector should improve matters, but many problems may have to be resolved before that office becomes an effective

AGO 532855

operation. Thus, AEIDC recommends that the State address major issues such as cost reimbursement, gas conditioning plant, and the pipeline design process in the Joint Federal-State Cooperative Agreement or in other ways.

In general, North Slope gas is desirable. The questions are when it will be delivered and at what cost. International scientists apparently believe that a chilled gas line can not be buried except at great cost, although a buried line is what Northwest proposes. In conclusion, AEIDC states,

> "The development of the necessary technology for the design and construction of this project has not kept pace with the rhetoric of the statements by Northwest Alaskan that they can complete the project efficiently and in an acceptable way (both technically and environmentally) with the stated time frames."

INSTATE USE OF NORTH SLOPE NATURAL GAS

1. "Preliminary Analysis of Markets for Gas Distribution to Pipeline Corridor Communities" by Northwest Alaskan Pipeline Company, May, 1979 (released July 27, 1979)

The Northwest Alaskan report concludes from its preliminary analysis of instate markets that use of North Slope natural gas for heating and electrical generation in the Fairbanks area appears economically feasible. Similar use of the gas

AGO 532856

in other pipeline corridor communities may be only marginally economical. However, the report does not include any analysis of the effects of the recent OPEC oil price increases. Northwest reiterated its support for establishing gas taps along the pipeline corridor, suggesting that the next step is "an economic feasibility analysis by the State." The price of gas depends on three factors: (1) field price; (2) pipeline transportation costs; and (3) distribution costs. The distribution costs are likely to be the major cost for any instate use.

Fairbanks Area Markets: If electrical power generation is part of the Fairbanks area demand, then, the report suggests, an adequate market for natural gas exists in the area. Electrical generation at Ft. Wainwright and Eielson Air Force Base is expected to remain coal-based. Northwest found "a strong interest in the private sector" in natural gas distribution "provided the gas can be competitively priced relative to other fuels."

Delta Area Markets: Northwest identified these possible markets: grain drying complex; space heating for Ft. Greeley, Delta Junction and Big Delta; and electrical generation for the Delta area. Promoters of Delta agricultural growth are interested in using natural gas, and two of the three proposed sites for a grain drying/elevator complex are "only 600 feet from the pipeline right-of-way."

AGO 532857

Tok Area Markets: Possible space heating and electrical generation use exists in the Tok area. "The use of natural gas to generate electricity appears more promising than home heating distribution."

The Northwest report briefly discusses the factors affecting the economic feasibility of local gas distribution systems. The "load," the volume of demand and whether it is sufficient to pay for delivery costs, is the key economic factor. The delivered gas price cannot be more than the price of No. 2 home heating oil on a BTU-equivalent basis if it is to be economically attractive.

The high volumes of gas required for Alaskan winter heating would leave the system operating "at much less than capacity for the remainder of the year." Without local industrial customers to take up the offseason load, the corridor gas distribution systems "would face severely low load factors (that) would greatly increase their cost per million Btu delivered."

Another factor in instate gas use would be the timely conversion of existing heating systems to gas usage, and the economics of making the conversions. The report also indicates that additional industrial use, such as electrical generation and grain drying, improves the economics of pipeline corridor gas distribution systems. The report concludes, however, that in communities other than Fairbanks, "economic feasibility is marginal."

AGO 532858

In a cover letter accompanying the report, Northwest noted, however, the following:

(1) The report does not include any economic analysis of the effects of the recent OPEC oil price hikes (or projected growth in oil prices over the next few decades);

(2) The report does not anticipate any major new industrial markets, except the Delta grain drying complex;

(3) The report does include the use of gas for electrical generation as it appears that the Federal Energy Regulatory Commission may allow such use for power generation in lieu of heating oil use.

It should also be noted that the report examines only the use of natural gas through direct taps and distribution systems, not the potential uses of such gas-based products as propane for instate heating.

GAS SALES

With Atlantic Richfield's recently announced gas sales, all Prudhoe Bay gas (except the State's royalty share) is now covered by sales contracts, tentative as those contracts may prove to be. The total estimated volume of Prudhoe Bay gas is about 26 Trillion cubic feet, or 2.4 Billion cubic feet/day. Of that total ARCO owns 31.5%; EXXON, 31.5%; SOHIO, 23.5%; and State of Alaska, 12.5%.

AGO 532859

As a result of the three producers' tentative sales, the Prudhoe Bay natural gas should go to the following gas transmission companies: *Northern Natural Gas, 18.3%; Columbia Gas Systems, Inc., 15.5%; Michigan Wisconsin, 10.5%; *Pacific Gas & Electric, 10.5%; *Pacific Interstate Transmission, 10.5%; *Panhandle Eastern Pipeline, 6.3%; *United Gas Pipeline Co., 4.73%; Texas Gas Transmission Corp., 3.78%; and Texas Eastern Gas Pipeline Co. and Transwestern Pipeline Co. (both subsidiaries of Texas Eastern Transmission), 3.15% each. The State has not entered into sales contracts for its 12.5% share of the total volume.

Those companies starred with an asterisk (*) above are current partners in the Northwest Natural Gas Transportation Co., sponsors of the Alaska segment. Of the pipeline project partners, only Northwest Energy Co. has not purchased North Slope gas, nor is it expected to. Those companies which have agreed to purchase North Slope gas but which have not become Northwest partners are Columbia, Michigan Wisconsin, Texas Gas, and the two subsidiaries of Texas Eastern Transmission.

This report was prepared on behalf of the Joint Gas Pipeline Committee by Mary Halloran, Research Analyst.

AGO 532860

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES
REP. BILL MILES, CO-CHAIRMAN
REP. C.V. CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

MID-INTERIM REPORT

Joint Gas Pipeline Committee
Alaska State Legislature

October 10, 1979

INTRODUCTION	pp. 1-2
GAS PIPELINE FINANCING	pp. 2-16
Regulatory Issues	p. 3
Constitutionality of Using State General Obligation Bonds for Equity Participation	pp. 3-5
Bonding Authority	pp. 5-7
Availability of State Funds for Investment	p. 8
Federal Assistance to the Gas Pipeline	pp. 9-14
Northwest's Stance toward State Participation	pp. 14-16
OTHER REPORTS	pp. 17-25
West Coast Oil Surplus	pp. 17-20
Producer Benefits Model; Sadelrochit Formation, Prudhoe Bay Field: A Description of a Policy Evaluation Model	pp. 20-22

AGO 532861

MID-INTERIM REPORT
Joint Gas Pipeline Committee
October 10, 1979

The Doschers Group	pp. 22-23
H.K. Van Poollen and Associates	pp. 23-24
Arctic Environmental Information and Data Center	pp. 24-25
CONDITIONAL PLANT	pp. 26-28
CURRENT CONTRACTS	pp. 28-29
A CLOSING NOTE	p. 30

AGO 532862

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES
REP. BILL MILES, CO-CHAIRMAN
REP. C.V. CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

MID-INTERIM REPORT

Joint Gas Pipeline Committee
Alaska State Legislature

October 10, 1979

The Joint Gas Pipeline Committee met formally June 4, 1979, in Anchorage to organize the Committee's work for the interim. (A report on that meeting is attached). Since that time Committee members have had informal discussions with the new Federal Inspector for the Pipeline, John Rhett; Canadian Pipeline Commissioner, Mitchell Sharp; and, on more than one occasion, Northwest Energy president, John McMillian.

The Committee co-chairmen, Sen. Mike Colletta and Rep. Bill Miles, served on the Governor's Blue Ribbon Working Group on the Gas Conditioning Plant for Prudhoe Bay Gas. In addition, Rep. Miles and House members, Speaker Terry Gardiner and Rep. Sam Cotten, traveled to New York and D.C. to discuss the gas pipeline project with major Wall Street investment firms, members of the Federal Energy Regulatory Commission (FERC), and White House and Congressional staff.

AGO 532863

Recently Sen. Colletta and Don Wold of the Alaska Royalty Oil and Gas Development Advisory Board traveled to Tulsa, Oklahoma, and Houston, Texas, to investigate the interest of major petrochemical firms in gasline-connected petrochemical development in Alaska.

Members of the Committee have worked extensively on gasline-related issues through other forums. A two-day hearing on the management of the Prudhoe Bay reservoir was held by the House Resources Committee, under the direction of Co-chairman Miles, during the August Special Session. Several Committee members, as well as other legislators, presented testimony at the September 4-6 FERC hearings on the Draft Environmental Impact Statement for the gas conditioning plant and pipeline pressure issues.

GAS PIPELINE FINANCING

The Committee has received much informal and formal information on different aspects of the gas pipeline financing, and the State's options for participation in project financing. The following sections will review that information.

1. Regulatory issues:

In a major ruling, the FERC issued a final Incentive Rate of Return (IROR) order September 6. The order sets a 17.5% rate of return as a centerpoint for equity investors in the Alaska and Northern Border segments of the project. The order, however, may be indirectly challenged in other FERC proceedings as it sets the framework for gas producers to pay gas conditioning costs, an item of strong contention. Another still unresolved tariff-related concern is tracking -- how to allocate costs to consumers and gas service companies for Canadian gas flowing in the pipeline system before the full system goes into operation. On the strength of the IROR and other favorable regulatory decisions, Northwest currently plans to have a financial plan in place by the end of this year and to talk with investment markets during the first quarter of next year.

2. Constitutionality of Using State General Obligation Bonds for Equity Participation in the Gas Pipeline

In a July 9, 1979, memorandum, State Bond Counsel Wohlforth and Flint confirmed the earlier conclusions of Billy Berrier, Director, Division of Legal Services, Legislative Affairs

Agency. In brief, Wohlforth and Flint stated that the constitutionality of using State General Obligation bonds for equity participation in the gas pipeline would rest on two points:

> "First, the project so financed must constitute an asset of relatively permanent value; and, second, the issuer of the bonds must retain some legal interest in the project."

That legal interest, suggested Wohlforth and Flint, could be through a "tenancy in common, mortgage, deed of trust, or other security interest in the pipeline."

The memorandum made clear that the spinoff benefits of the pipeline construction and operation are not sufficient legal grounds to render General Obligation bonds constitutional.

> "Mere general improvement of public prosperity and welfare, and even removal of economic insecurity, while viewed as laudable purposes, do not in themselves constitute capital improvements."

After examination of the related court cases, Wohlforth and Flint concluded that investment of State General

Obligation bonds could probably meet the "physical" requisites of the "capital improvements" restriction on such bonds. They added,

> "However, the state must acquire sufficient legal interest in the capital improvement to overcome the constitutional deficiencies set forth in Hixson. An investment by the state of bond proceeds in 'equity related securities' does not meet this test. The financing must be accompanied by some form of interest in the pipeline. Clearly, the interest would have to be equivalent in value to the amount of bond proceeds devoted to its acquisition."

3. Bonding Authority

In 1978, the State Legislature passed AS 44.55, establishing the Alaska Gas Pipeline Financing Authority, commonly referred to as the Bonding Authority. The Authority is a mechanism by which the State may issue up to $1 billion in tax-exempt bonds for construction of the gas pipeline.

Northwest Pipeline Company sought to have consideration of revisions in the Bonding Authority legislation placed on the August Special Session agenda. Although that step was not

taken, consideration has been given to technical changes which may be needed to clarify the Authority's legal ability to issue bonds.

In a September 21, 1979, report to Revenue Commissioner Tom Williams, Director of the Bonding Authority, Attorney John Messenger outlined those technical changes. Messenger did not discuss, nor was he asked to review, the policy matters inherent in the financial and Alaska impact plan called for under AS 44.55.

In general, the possible technical changes Messenger reviewed include:

(1) clarification and broadening of the purposes for which bonds of the Authority may be issued;

(2) a. provision that legislative approval of the financing and Alaska impact plan (hereinafter referred to as the Plan) and legislative approval of bonds be contained in separate concurrent resolutions;

b. provision that legislative approval of the bonds may contain such limitations as the Legislature deems appropriate;

c. elimination of the requirement that bonds be issued and sold in accordance with the Plan;

(3) revision of the statute sections dealing with refunding bonds so that confusion over the approval process for such bonds is eliminated;

(4) provision for amendments of the Plan after passage by the Authority of a resolution authorizing sale of the bonds;

(5) provision for approval of the Plan (or a conditional Plan) by concurrent resolution;

(6) addition of language excluding the Authority or its bonds from AS 37.10.085 which prohibits the State from lending its credit or borrowing money for the use of a corporation;

(7) revision of AS 44.55 to include certain requirements which would meet proposed IRS regulations concerning the Authority's ability to act "on behalf of" the State and thus to issue tax-exempt bonds;

(8) modification of the Legislative findings to support the conclusion that gas pipeline financing by the Authority is for a public purpose; and

(9) other minor textual changes.

Messenger is drafting legislation embodying these changes for consideration by the Administration and the Legislature.

4. Availability of State Funds for Investment in the Gas Pipeline Project

In an August 3, 1979, memo, Fiscal Analyst Milt Barker, of the Legislative Finance Division, reviewed whether projected FY 80 State revenues would permit an appropriation of $500 million for a direct investment in the gas pipeline. Barker concluded sufficient funds do exist whether such an appropriation was paid over at once or drawn down over a period of time. He cautioned, however, that FY 80 receipts depend, in substantial part, on the results of pending litigation over the petroleum income tax.

The Legislative Finance Division did not analyze -- nor was it asked to do so -- the financial policy implications of a $500 million direct appropriation to the pipeline project or the economic opportunity costs to the State of taking that action. The Division has been asked to prepare -- and the Committee expects to receive shortly -- an analysis of all projected revenues, both direct and indirect, the State would obtain from the successful construction and operation of the gas pipeline.

5. Federal Assistance to the Gas Pipeline

A July 27, 1979, report by the law firm of Birch, Horton, Bittner and Monroe examined current prospects for federal assistance to the gas pipeline. Prepared by attorney Joseph Chomski, with the assistance of Richard Haggart and Lisa Nelson, the report described possible forms of Federal financial participation as follows:

(1) Direct loans to the project;

(2) Loan guarantees for the project;

(3) Federal guarantee of the prices of the gas supplies;

(4) Federal guarantee of Federal government purchases of such gas supplies.

These forms of federal support could be possible through Congressional passage of President Carter's proposed Energy Security Corporation legislation.

The most likely form, Chomski concluded, is provision of loan guarantees for at least a portion of the pipeline project. The loan guarantees would be structured within the parameters proposed in the Energy Security Corporation legislation, the report suggested.

Another "much more remote" possibility for federal assistance would be provision of purchase guarantees for some or all of the North Slope gas. Such an approach would involve a "subsidy loss to the Treasury," an alternative the report authors find "extremely unlikely."

Regardless of the form, the probability of federal financial assistance "has become quite likely." The report states,

> "Thus, in the event that the project fails to finance privately, as now seems likely based on numerous expressions from the financial and energy community, federal financial support would seem to be very likely in that federal assistance to the project would result in the easiest, least expensive (to the federal government), earliest, largest, and -- most importantly -- surest single increment to the nation's energy supply of any of the options available to the federal government."

Federal participation is unlikely to be forthcoming "until Northwest concedes that it cannot finance the line privately (as promised to Congress) and either directly or via the Administration requests federal assistance." Congressional

feeling, the authors found, towards federal backstopping remains negative as does public support for such action. In addition, no evidence was found of a White House initiative to change its stated policy opposing federal financing for the project.

The report analyzed Northwest's reasons for not changing its position with regard to requesting federal assistance. The reasons are twofold:

(1) A Northwest request for federal assistance "will create major political problems for the project and for the existing project management."

> "Consequently, we believe one major motivating factor for Northwest's not throwing in the towel on the private financing approach at this time is the fact that they must appear to have foreclosed every reasonable alternative to federal assistance before they return to Congress."

(2) Northwest wants to establish a clear public record that any failure of private financing is not the fault of project sponsors but rather of the federal regulatory process, and perhaps also of the oil companies (the gas producers) and the State of Alaska.

For a number of reasons, the report authors believe that provision of federal financial assistance to the project will not occur before spring 1980 and more likely in 1981.

In conclusion, the report suggests steps the State may take in support of federal financing and of the project in general:
(1) Provide Congress and senior Energy officials with information of positive State actions taken with respect to the project;
(2) Conduct private and frank discussions with Northwest officials about the need for federal assistance; and
(3) Take steps to protect the State's interests by positive action on Alaska's own program of financial assistance.

The need for eventual federal assistance to the project stated in the Chomski report was, in large part, substantiated by the findings of Rep. Miles from May visits with Wall Street investment firms, federal energy officials and White House and Congressional staff. In a June 18, 1979, memo, Miles reviewed several issues, including federal guarantees, Alaska's role, Canada's role, the Federal role, regulatory activity, conditioning plant, producer participation, expansion of the Northwest partnership, the El Paso proposal and future action. As that memo was distributed to all legislators, only brief

mention of its contents will be made in this report.

Miles indicated that Wall Street firms believe that some form of federal financing for the project will probably be needed. In contrast, the federal officials stated that the Federal government's goal is still a "purely privately-financed project." Alaska's financial participation at this time was generally seen by Wall Street as a cosmetic or psychological gesture, but not as an action which would "make or break" the project. Such participation, however, was strongly encouraged by the federal officials.

According to Wall Street, the most necessary components needed by the project at this time are:

(1) producer participation;

(2) a reasonable attitude by regulatory agencies;

(3) Canadian-U.S. interaction, especially on the Eastern leg; and

(4) additional expenditures by the project sponsors for design, engineering and other technical work.

The federal officials, Miles found, felt the four components vital to the project at this time are:

(1) producer participation;

(2) State of Alaska equity participation;

(3) an expanded Northwest partnership; and

(4) more aggressive assistance from the Federal administration.

In addition, federal officials predicted that the major regulatory issues, such as conditioning costs, rate of return, and pipeline pressure, would be both ruled on and litigated by this fall.

6. Northwest's Stance Toward State Participation in the Gas Pipeline

On August 29, 1979, John McMillian, Northwest president, sent letters to both President Jimmy Carter and Governor Jay Hammond about Northwest's "lack of success in obtaining financial commitments from the State of Alaska in a timely manner." To Hammond, McMillian wrote, "Therefore, we hereby withdraw the proposed financing plan and the other arrangements based thereon which we have with the State of Alaska."

McMillian presented, however, two other financing concepts for the Governor's consideration:

(1) State participation in the entire project in relation to its 1/8th royalty gas,

> "The state could provide 1/8th of the debt permanent structure, 1/8th of the construction overrun contingency fund, and some acceptable form of completion guarantee;"

(2) Structure State participation on the basis of participation by the oil companies,

> "Another thought would be to wait and see what the final participation of the oil companies in the project will be and the state could then be expected to have a financing package similar to that of the oil companies."

In the letter to President Carter, McMillian stated that Northwest's original proposal to the State "is, as evidenced by two years of frustrating delays, evidently not acceptable to the State." He went on to say,

> "We have never been able to explain the concept of tax-exempt bonds to the legislative members.

> Therefore, we are now suggesting another plan whereby the State participates in 1/8th of the debt structure, 1/8th of the construction overrun contingency fund, and some form of completion guarantee."

McMillian called the 1/8th concept "a fair and reasonable request," and asked Carter to make a request to Governor Hammond and Alaska for Alaska's participation in project financing. He concluded,

> "If, even after your recommendations, we are not successful in obtaining the State's help and participation in project financing, it may be necessary to consider special federal legislation which will ensure that the State does not retain all of the project benefits, such as intrastate use of Alaska gas for Alaskans, and a very favorable wellhead gas price, without sharing in the debt structure of the project."

In his remarks to an Anchorage gathering October 5, 1979, McMillian reiterated his withdrawal of Northwest's previous financial proposal ($1 billion in tax-exempt bonds and $500 million in equity from the State) and mentioned the 1/8th approach as Northwest's new concept for financing. Everything, said McMillian, is open to renegotiation.

OTHER REPORTS

In addition to the above-mentioned reports on gas pipeline financing, the Committee has received several reports on related issues. Those reports are reviewed in this section.

1. Final Report, West Coast Oil Surplus by Arlon Tussing

In an August 20, 1979, memorandum economist Arlon Tussing submitted his final report on the West Coast oil surplus issue. Tussing was under contract to help develop a strategy to solve the problem of "loss of state royalties and production taxes caused by the high cost of shipping 'surplus' Prudhoe Bay crude oil to Gulf and East Coast markets."

The problem was "solved," so to speak, by the agreement of North Slope oil producers to pay state royalties on the basis of the federal ceiling price, as of July 1, 1979, regardless of the oil's destination or transportation cost. The producers will also pay production taxes at the same rate. "Hence, exports or exchanges can no longer improve the state's immediate royalty and tax position," said Tussing.

The State's effort to negotiate and get federal approval for international exchanges of Prudhoe Bay royalty oil would have been stalled, in any case, by the Congressional adoption of restrictive amendments to the Export Administration Act. The U.S. Senate, for example, adopted the Riegel Amendment which will make any future exchanges of North Slope crude difficult. The "surplus" problem will resurface for the State when federal price ceilings on crude oil prices are removed. The decontrol of crude oil prices, now scheduled for June 30, 1981, will make the Prudhoe Bay wellhead price again a netback price, determined by the oil's market value, less transportation costs. Under those circumstances, the State's fiscal interests would again be served by exports or international exchanges (as long as North Slope crude cannot be delivered to the nearest markets on the West Coast).

Tussing assessed the State's efforts to date to liberalize federal export restrictions as follows:

(1) The efforts resulted in the Department of Energy conducting a formal study of the issue and DOE's ultimate position in favor of exports;

(2) The proposed PEMEX exchange allowed the State to explain its case to a national audience and to receive national editorial endorsement;

(3) Meetings between Alaska and California officials gave Alaskans "better insight into both the economics and the politics of petroleum on the West Coast and nationally;"
(4) Sohio's active cooperation, essential to the PEMEX proposal, was not realized, and Sohio's termination of the PAC-TEX project created Congressional ill-will toward any future exchanges which might benefit Sohio;
(5) The efforts "clearly failed" in Congress and "we may have failed only for lack of trying." Administrative and legislative indecision over whether to launch a serious lobbying effort led to no campaign by default.

Tussing also reviewed related issues, such as the use of North Slope crude in West Coast refineries, refinery modifications and grassroots refineries on the West Coast, and West-to-East oil pipelines.

The California Energy Commission, Tussing indicated, is today concerned about California refineries' high dependence on North Slope crude. The Commission wants to reduce that dependence and have contingency plans to deal with a possible cutoff. A North Slope cutoff would cause California to suffer "noticeable shortages in about seven days, and would result in serious economic disruption within two weeks."

The picture for West Coast refinery modification and grassroots refineries is more complex. The growing scarcity of light crudes calls for major modifications in refineries. But, the fact is that present US and West Coast refineries may "already have as much gasoline capacity as the industry will ever need." Contributing to investor uncertainty are unsteady federal policy with respect to future production standards for gasoline and other regulatory restrictions.

The West-to-East oil pipeline proposals are not economically competitive with expansion of existing midcontinental pipelines without supplies of additional overseas crude oil. Such additional foreign supplies have been ruled out by President Carter with an announced ceiling on imports set at the 1978 levels.

2. Producer Benefits Model; Sadelrochit Formation, Prudhoe Bay Field: A Description of a Policy Evaluation Model, by Lawrence Eppenbach

Through work begun with the Division of Legislative Research and completed under contract to the Department of Natural Resources, Eppenbach has set up a computer program series. The "Producer Benefits Model" evaluates Prudhoe Bay geological

information along with the costs of alternative methods of developing the reservoir. Based on data prepared by H.K. Van Poollen and Associates and, to a limited extent, information provided by the field operators, the model can be used to "forecast state revenues and industry cash flows associated with alternative policy options. It also calculates the net present values of these future returns in order to compare the value of one policy option to another."

In addition, the series of computer programs allows the operator to set varying parameters for the analysis:
--whether to use constant dollars or to include the effect of inflation;
--how the producers expect to finance their capital expenditures;
--what future wellhead values are likely to be; and
--what discount rate should be used to calculate the net present values.

The model results should provide useful comparisons between one field development plan and another. It will also clarify any differences in economic incentives between the State and the industry. The scope of the model is limited, however,

to the Sadelrochit formation and only to field economics. Also it does not examine the economics of gas liquids production. Although more basic data is needed before the model can begin producing useful results, the model is now operational. It is available through the Division of Minerals and Energy Management, Department of Natural Resources.

Eppenbach's report includes sample outputs and contains program listings.

3. Progress Reports - The Doschers Group

Dr. Todd Doscher provides the Committee with an ongoing written overview of the work of H.K. Van Poollen and Associates on the State's three-dimensional reservoir model of Prudhoe Bay. Based on his work to date, Dr. Doscher's central conclusion is "that gas sales should not be committed until the need for water injection to at least compensate for gas withdrawals is firmly established, and still not then."

Gas withdrawals should not take place, Doscher indicates, until sufficient Prudhoe Bay reservoir performance history can be accumulated so that the effects of such withdrawals can be adequacely inferred.

Other areas of concern to Doscher are Prudhoe Bay reservoir pressure maintenance, the "nebulous plans" of the operators with respect to water flooding, and the need for the State to assure the ultimate Prudhoe Bay oil recovery efficiency will be increased from the base 20% level to 40%. These and other concerns prompt Doscher to not only recommend no gas sales at this time, but to "express grave concern about increasing oil withdrawal rates."

Major technical problems in the three-dimensional work thus far have been "the assignment of permeabilities and the positioning of shale barriers in the model of the reservoir."

4. Progress Report - H.K. Van Poollen and Associates and the Alaska Oil and Gas Conservation Commission

H.K. Van Poollen and Associates, under the direction of the Alaska Oil and Gas Conservation Commission, are responsible for a three-dimensional reservoir simulator model of the Prudhoe Bay reservoir and its performance. The purpose of the study is threefold:

(1) should there be gas sales or not, and, if so, how much;

(2) should pressure maintenance be employed, and if so, how much; and

(3) are the field oil and gax maximum production rates allowed under Oil and Gas Conservation Order 145 still valid.

Confirming match runs between the earlier two-dimensional computer model and the three-dimensional model are being run at this time, with comparison runs scheduled soon. These latter runs will look at ultimate oil recovery, with and without gas sales, and with and without water injection. A report is expected to be released by the end of this month on this work. Then, it is planned to do a series of "what if" runs which will explore questions such as the effect of rate of production on ultimate oil recovery. A report on these latter findings is expected by the end of November.

5. Progress Reports - Arctic Environmental Information and Data Center (AEIDC)

The AEIDC is collecting information on the status of technical, environmental and other matters relating to the pipeline project.

Under AEIDC review are the right-of-way and proximity issues affecting the design and construction schedule of the project. The materials submitted with the AEIDC reports to date indicate that many specific technical issues still require resolution prior to a final right-of-way decision by the Department of Interior. One major concern is the risk to the TAPS oil line from building the gas pipeline in close proximity.

Another technical issue is the lack of definitive data on how the project sponsors will handle the problems of pipeline construction and operation in permafrost soils. Other issues include liability of TAPS owners with respect to joint use of the right-of-way, mitigation of impacts to fish and wildlife, and minimization of gas pipeline crossings with the TAPS oil line and the North Slope haul road.

A full report will be prepared by the AEIDC by October 15, 1979.

CONDITIONING PLANT

An issue which generated considerable discussion has been FERC's August 6, 1979, pipeline pressure order, its impact on the eventual location of the gas conditioning plant for the project and its effects on the viability of future instate use of North Slope natural gas. Also at issue are the conclusions and much of the content of FERC's Draft Environmental Impact Statement released July 27, 1979.

In response to widespread concern, Governor Jay Hammond appointed a Working Group on the Gas Conditioning Plant. The group's members included Sen. Colletta and Rep. Miles as well as administrative officials who are ex officio members of the Joint Gas Pipeline Committee. During September subcommittees of the Working Group met in several sessions to review the following:

(1) the State's progress to date in the FERC proceedings;

(2) benefits and costs of locating the conditioning plant in the Interior instead of Prudhoe Bay;

(3) alternatives for instate use of Prudhoe Bay natural gas and/or natural gas liquids;

(4) the likelihood that the State would prevail in an appeal of the FERC size and pressure order; and

(5) the effects on the gas pipeline project -- especially in terms of delay -- if the State were to appeal the FERC size and pressure order.

Based on its review of these items, the Governor's Working Group made several findings and resolved the following:

(1) the subcommittees' reports, approved by the full Working Group, be transmitted to the Governor as the preliminary report of the Working Group;

(2) the Governor be requested to determine the present-day feasibility of an instate petrochemical industry, particularly by actively contacting and soliciting the interest of major petrochemical companies with regard to the feasibility of such development; and

(3) the Governor be requested to preserve the State's options by requesting FERC to re-open for hearing the size and pressure issue for the project and, failing that, filing an appeal of the FERC size and pressure order no later than October 5, 1979.

The Working Group's September 21 resolution was accompanied by another asking the Governor to continue the Working Group, by allowing its members to serve as ex officio members of the Legislature's Joint Interim Gas Pipeline Committee.

CURRENT CONTRACTS

Many of the reports discussed earlier in this document were completed under FY 79 contracts. Currently, the Committee has the following firms and/or individuals under contract:

(1) The law firm of Birch, Horton, Bittner and Monroe - a $25,000 contract to provide written monthly reports on matters affecting approval and effectuation of the proposed gas pipeline. The contract runs September 1, 1979, through June 30, 1980. Project directors are Sen. Colletta and Rep. Miles;

(2) The Doschers Group - completion of an extended FY '79 contract for $20,000 which calls for Doscher to act as an independent technical advisor on matters related to oil and gas reservoir management policy. The contract ends December 31, 1979. Project director is Rep. Miles;

(3) H.K. Van Poollen and Associates - completion of an extended FY '79 contract for $60,000 which calls for Van Poollen to develop a methodology for analyzing the development options of the Prudhoe Bay reservoir, i.e. the three-dimensional reservoir simulator computer model. The contract runs through December 31, 1979. The work is being carried out under the direction of the Alaska Oil and Gas Conservation Commission. Rep. Miles is the project director;

(4) Arctic Environmental Information and Data Center - a $15,000 contract to provide information on technical and environmental issues related to construction and operation of the gas pipeline. The AEIDC final report is due October 15, 1979. Rep. Chat Chatterton is the project director; and

(5) Lazard Freres - a $50,000 contract to provide analysis and examination of a possible State equity investment in the gas pipeline project. The contract ends June 30, 1980.

A CLOSING NOTE

Copies of many of the documents mentioned in this report are available through the Legislative Library, Legislative Affairs Agency, Pouch Y, Juneau, Ak. 99811. All documents are also on file with the Joint Interim Gas Pipeline Committee, 727 N St., Suite 2, Anchorage, Ak. 99501. This report was prepared by Mary Halloran, Research Analyst, on behalf of the Joint Gas Pipeline Committee.

AGO 532892

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA
CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES

REP. BILL MILES
CO-CHAIRMAN
REP. C.V. CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR

EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

May 20, 1980

To: Legislative Reference Librarian
From: Mary Halloran, Research Analyst

Attached are a set of the key memos and reports from the 1979 interim work of the Joint Gas Pipeline Committee.

Legislative Reference Library
Legislative Affairs Agency
Pouch Y State Capital
Juneau, Alaska 99811

AGO 532893

Joint Interim Gas Pipeline Committee

SEN. MIKE COLLETTA — CO-CHAIRMAN
REP. BILL MILES — CO-CHAIRMAN
SEN. FRANK FERGUSON
REP. C. V. CHATTERTON
SEN. BILL SUMNER
REP. TERRY GARDINER
EX-OFFICIO MEMBERS
MR. FRED BONESS
MR. JACK BACHMAN

727 N St., Suite 2
~~1016 WEST 6TH AVENUE, SUITE 405~~
ANCHORAGE, ALASKA 99501
~~(907) 274-3331~~
(907) 276-4340

June 15, 1979

REPORT FROM THE JOINT INTERIM GAS PIPELINE COMMITTEE
Alaska State Legislature
727 N St., Suite 2, Anchorage, Ak. 99501
By Mary Halloran, research analyst

The Joint Interim Gas Pipeline Committee met June 4, 1979, in Anchorage, taking the following actions:

COMMITTEE ACTIONS:

1. The Gas Pipeline Committee requested that the Legislative Finance Division, working with Legislative Research, make a formal presentation at the next committee meeting, tentatively scheduled for the beginning of August.
   The report is to follow up on earlier Legislative Finance forecasts that state general fund revenues will be insufficient to support a direct cash investment of $500 million in the Northwest gas pipeline project, even under the most optimistic circumstances.
   Commissioner Tom Williams, Dept. of Revenue, stated that the Dept. of Revenue's next quarterly report will be available by mid-June for the Committee's review.

2. The Gas Pipeline Committee and Commissioner Williams also agreed that $60,000 allocated to the Dept. of Revenue for financial and legal work regarding the gas pipeline could be used, in part, to obtain for the committee:

   (1) a formal opinion of bond counsel on whether general obligation bonds may be legally used to finance state equity participation in the gas pipeline; and

   (2) if bond counsel determines that the use of general obligation bonds would be legal for this purpose, expert financial opinion on how the issuance of bonds would affect the state's ability to finance other needed capital projects.

   The work is to include a consideration of the effect also of tax-exempt bonds on the state's participation in the bonding market. Tax-exempt bonds have been authorized under the Gas Pipeline Financing Bonding Authority, given the fulfillment of several specific conditions.

   The Gas Pipeline Committee committed $5,000 to the work, with the understanding that Reps. Chat Chatterton and Charlie Parr would work with the Dept. of Revenue on the project.

AGO 532894

3. Attorney Ron Birch was asked to prepare a tentative report on the possibility of federal participation in the gas pipeline project financing. Birch will prepare the report for the committee's August meeting. Preliminary work on the subject done by consultants to the Dept. of Revenue will be shared by Revenue with Birch.

4. A $15,000 contract with the Alaska Environmental Information and Data Center (AEIDC) was approved by the committee. AEIDC will investigate the current status of unresolved technical issues in relation to construction of the gas pipeline.

   A report by AEIDC will be submitted to the Legislature October 15, 1979. The report will cover areas such as thermal regime effects, hydrology and ground water concerns, proximity to TAPS (criteria and risk analysis problems), work pad criteria, construction issues, design pressure determinations and effects. Rep. Chatterton is the contract project director.

5. The Gas Pipeline Committee will also work with the state administration and Northwest Alaska Pipeline Company to study the conditioning and processing issues of the gas pipeline project. The committee committed $25,000 to the study, with another $25,000 coming from the Dept. of Revenue and another $25,000 from Northwest. Rep. Bill Miles will work with Commissioner Williams and Jack Bachman, Northwest representative, on the study.

   In addition, the Dept. of Revenue also has current contracts to continue work begun earlier by Purvin and Gertz on the concept of a publicly owned conditioning plant.

Committee members at the meeting were Sen. Mike Colletta, Rep. Bill Miles, Rep. Charlie Parr, Rep. Chat Chatterton, Commissioner Robert LeResche (ex officio) and Jack Bachman, Northwest (ex officio).

Also present were Commissioners Tom Williams and Charles Webber; Gregg Erickson and Larry Eppenbach, Legislative Research; John Sund, counsel to the Speaker of the House; Mary Halloran, research analyst; and Ron Birch and Lisa Nelson, legal consultants.

The committee's next meeting is tentatively scheduled for early August.

UPDATE ON GAS PIPELINE EVENTS

EXXON SELLS GAS; BUYERS TO PAY CONDITIONING COSTS

Pacific Gas and Electric, Northern Natural and Michigan-Wisconsin Gas Transmission Company have each concluded contracts with EXXON for one-third of its interest in Prudhoe Bay gas production.

PG&E and Northern Natural are partners in the Northwest consortium, while Michigan-Wisconsin, according to Northwest representative Jack Bachman, has approached Northwest about joining the group.

A significant contract stipulation is that the gas purchasers would pay for conditioning costs, contrary to the Federal Energy Regulatory Commission's ruling that producers, not purchasers, would bear the burden of conditioning costs.

EXXON would assume the costs of gathering lines, dehydration equipment, field compression equipment, cooling facilities, and related facilities. It has also, under the contracts, agreed to shoulder any future costs associated with artificial lift and water injection programs. While the gas purchasers would pay for conditioning costs, they would own any liquids collected during the conditioning process.

The contracts indicate, according to legislative consultants Chomski and Haggart, "the willingness of at least one producer to oppose the FERC position directly, by adding treatment costs on top of Section 109 ceilings."

In an April 27, 1979, report to the legislature, Chomski and Haggart further concluded, "Simultaneously, we have seen no signs to date that the FERC is willing to modify its position on treatment conditioning costs to the satisfaction of the producers. While predicting the outcome of any regulatory proceeding is always hazardous, we see little prospect in the current dispute other than extended litigation. To the extent that this is the case, neither gas sales contracts nor financial commitments to the pipeline project can be finalized."

The State of Alaska joined EXXON and other major gas producers in filing comments with FERC earlier in opposition to FERC's conditioning costs proposal.

ALASKA GAS COULD BECOME POOR BUY FOR AMERICAN CONSUMERS

The Alaska gas pipeline "is likely to provide significant economic benefits to the nation," according to a study by ICF Inc. Commissioned by FERC, the study states, however, that benefits to the consumers may hinge on changes in construction costs and the value of gas.

The May report assumed a gas conditioning charge of zero to the consumers, adding that that assumption is "especially critical" to its analysis. "Specifically, imposition of the full costs of gas conditioning on gas purchasers would reduce the consumer share of benefits considerably, with consumers being worse off, relative to using distillate fuel oil by more than $1.9 billion (mid-1979 dollars)."

Besides conditioning costs, the other major factor impacting the benefits of gas consumers is construction costs. The report states, "This conclusion-that the Alaskan gas project should be in the interest of both the nation and the nation's gas consumers- is valid if the ANGTS were constructed at a cost in line with current estimates. Consumers, however, could lose $2.2 billion if construction problems lead to the high cost case for the pipeline construction."

The report goes on to say that other parties - gas producers, the Alaskan and federal governments, and the pipeline owners - would still benefit even if construction costs rise.

ALASKA RATE OF RETURN SET BY FERC

A 17.5 percent center rate of return on investors' money has been set by FERC if project construction costs are 30 percent higher than estimated in March 1977. At that time, the cost was pegged at $10.5 to $13.9 billion by Alcan, Northwest's predecessor.

In earlier comments on FERC's proposal, Northwest objected to tying the incentive rate of return to the March 1977 cost estimates as that approach ignores changes which have taken place since that time.

The rate of return is variable, with the profit rate declining as costs exceed 30 percent. In addition, FERC ruled that money used in cost overruns should yield only 8 percent return, rather than the 12 percent "marginal" rate requested by Northwest.

FERC also ruled that pipeline owners may charge "cost-of-service" transportation rates for gas shipped through the pipeline rather than adhering to a fixed transportation charge.

RHETT NOMINATED AS FEDERAL INSPECTOR; BEHLKE TAKES STATE COORDINATOR SPOT

The long-expected nomination of John T. Rhett as federal inspector for the gas pipeline was made recently by President Carter. An engineer and former colonel in the Army Corps of Engineers, Rhett has worked as the deputy assistant administrator for water programs at the Environmental Protection Agency since 1973. His nomination is still subject to Senate confirmation.

Dr. Charles Behlke, dean of the University of Alaska school of engineering, has been chosen as the state pipeline coordinator. Behlke also serves as chairman of the board of the Alaska Power Authority and chairman of the Capital Site Planning Commission. He begins his latest post as pipeline coordinator July 2.

CANADIAN SEGMENT READY TO GO

The Alberta segment of the gas pipeline may be under construction next year, according to Commissioner Mitchell Sharp of the Northern Pipeline Agency of Canada. Sharp's comments were echoed by British Columbia Sen. Ed Lawson who spoke in Anchorage in early June.

Both Lawson and Sharp indicated that "all systems are go" for pipeline construction in Canada. Lawson stated that some government financial assistance in Canada may be necessary to complete the project. The Alberta segment would initially move surplus Alberta gas, if approved by the Canada National Energy Board.

In the meantime, workers for Foothills, the sponsors of the Canadian segment, may be laid off while the Foothills group reduces its budget for preliminary work on the project. A company spokesperson announced June 7 that as many as 30 of the 225-member staff will be laid off. In an Associated Press report, the official explained, "Foothills was merely recognizing the 22-month delay that has occurred because of regulatory delays in the United States."

NO SPENDING BY NORTHWEST

Northwest partners have withheld action on the Alaska project budget of $38 million for this year, confirmed company representative Jack Bachman at the Joint Gas Pipeline Committee meeting in ANchorage June 4th. Bachman also stated that Northwest needs to know by the end of this year whether Alaska will contribute towards the project's financing. Northwest plans to file its financial plan with FERC in the first quarter of 1980.

Joint Interim Gas Pipeline Committee

SEN. MIKE COLLETTA — CO-CHAIRMAN
REP. BILL MILES — CO-CHAIRMAN
SEN. FRANK FERGUSON
REP. C. V. CHATTERTON
SEN. BILL SUMNER
REP. TERRY GARDINER
EX-OFFICIO MEMBERS
MR. FRED BONESS
MR. JACK BACHMAN

~~1016 WEST 6TH AVENUE, SUITE 425~~
ANCHORAGE, ALASKA 99501
~~(907) 274-8351~~
727 N St., Suite 2
Anchorage, Ak. 99501
(907) 276-4340

M E M O

To: All Legislators
From: Bill Miles
Re: Northwest Gas Pipeline
Date: June 18, 1979

Two weeks ago, Speaker Gardiner, Rep. Cotten and I traveled to New York and Washington, D.C. to work on a number of items. At separate meetings during the trip, we discussed the gas pipeline with the following:

New York

Loeb Rhodes
Lazard Freres
Merrill Lynch White Weld
Solomon Brothers
Kidder Peabody

Washington

Alaska's Counsel before Federal Energy Regulatory Commission (FERC)
FERC Counsel
FERC Staff
FERC Commissioner
Department of Energy
White House Aide for Domestic Affairs

The issues we discussed are summarized herein. Not all of the issues were discussed with each entity named above; the brief summaries below are meant to give an impression of the feelings of the majority of the people with whom we met.

1. FEDERAL GUARANTEES

Wall Street indicated that some form of federal financial aid to the line would probably be needed, although a slight chance existed for private financing if a number of things fell into place.

AGO 532899

In one case, a cost overrun for the Alaska segment by the federal government was indicated as the most likely form of federal aid. It was unanimously agreed that if the federal government became financially involved in the project, the cost of financing the line would be decreased. And, therefore, the project would be speeded up and the cost to consumers would be reduced.

The Federal Government indicated that its goal was still a purely privately-financed project as this has been the stated policy of the President and Congress. Federal representatives said that, of late, they had aggressively been pursuing various means to make private financing a possibility, and that they would continue to do so, using all the means available to them.

However, they acknowledged the problems facing a purely privately-financed project, noting a reservation to that conclusion by one Federal Energy Regulatory Commissioner. Additionally, in order for private financing to be available, a number of things were necessary: financial participation by the producers and the State of Alaska, and an expanded gasline partnership. Even these components, however, could not guarantee private financing.

2. ALASKA'S ROLE

Wall Street generally indicated that financial participation in the project by the State of Alaska would be helpful from a cosmetic or psychological standpoint, but would not "make or break" the project. Some representatives indicated other financial commitments should be in place prior to Alaska's possible participation. Some said it should come concurrently with other commitments. Some indicated Alaska should not participate in an equity manner. No one suggested Alaska make an equity commitment now.

The Federal Government strongly urged Alaska's financial participation as the State was one of the major beneficiaries of the project. Surprisingly, some federal representatives were unaware of the creation of the Alaska Gas Pipeline Bonding Authority which enables the State to place up to one billion in debt for the project. They also felt that a contribution by the State of Alaska to the project was a private financing tool as opposed to public financing.

3. CANADIAN ROLE

Wall Street felt that there were fewer inherent risks in the Canadian portion of the projects yet indicated a major concern over the length of Canada's National Energy Board (NEB) commitment to the Eastern leg of the project. The current six year commitment may be insufficient to finance the Eastern leg but the NEB has "left the door open" for increasing that term, provided all the other components of the full transportation system (conditioning plant, Alaska segment, Canadian segment and Western leg) fall into place.

4. FEDERAL ROLE

Wall Street indicated federal help will be necessary in a number of areas, including the financing aspects, regulatory aspects and the timing of the project. Wall Street realized the current active role the federal government was beginning to play in the project.

The Federal Government, in both its regulatory and administrative areas, is starting to move quickly on the project, i.e., the nomination of the Federal Inspector, the establishment of the rate of return, etc. However, a number of unresolved issues are still apparent, such as the allocation of conditioning costs (now estimated to be $2.8 billion), resolution of the pipeline routing questions, etc.

Additionally, the Department of Energy appears to be increasing its efforts in many areas to resolve other problems facing the project: the size of the pipeline partnership, the role of the producers, etc.

5. REGULATORY ACTIVITY

Wall Street indicated that the gasline tariff is causing potential lenders concern. Tariffs are set by regulatory agencies, one investment house argued, and they can be modified by regulatory agencies. On smaller projects, lenders are willing to take this risk so long as the record is clear on the importance of maintaining the rate. On this project, the willingness to risk the uncertainty of regulatory changes will be less. Hence, a clear record and possible legislation may be needed.

The Federal Government acknowledged the Wall Street concerns and that regulatory rules can have a re-hearing and be changed.

6. CONDITIONING PLANT

One Wall Street firm suggested that potential Alaskan equity might be better placed in the conditioning plant (now estimated at $2.8 billion) than in the gasline itself as any equity the State might produce would be lost in a multi-billion dollar project. Another firm indicated it had heard of a company that was willing to build the conditioning plant. Negotiations among the various interested parties are presently taking place in a more serious vein than earlier this year.

The Federal Government indicated the conditioning cost allocation question will be expedited in the courts this summer. Further, it confirmed negotiations concerning the conditioning plant are underway.

7. PRODUCER PARTICIPATION

Wall Street indicated a strong need for producer participation. In fact, several people said producer commitments to the project's financing were the next big step necessary toward completion of the line. Only then should the State consider financial participation.

The Federal Government also indicated a strong need for producer participation and further indicated it would do everything possible to see this aspect of project financing fall into place.

8. EXPANSION OF THE PARTNERSHIP

Wall Street indicated several potential new partners were considering joining the gasline partnership. This expansion would greatly assist the project by adding needed capital, markets, etc.

The Federal Government strongly supports adding new partners to the Northwest group. In fact, the government is actively seeking additional partners. One person made the assumption that a number of potential partners have not heretofore joined the partnership because many of the regulatory rules have not been set. As these issues are resolved, an expanded partnership is expected.

9. EL PASO PROPOSAL

The Federal Government indicated there was no possibility of re-opening the All-Alaska (El Paso) gasline proposal. Nor would there be any consideration given to other similar LNG proposals.

10. FUTURE ACTION

Wall Street generally agreed that the most necessary components needed by the project at this time are:

1. Producer participation;
2. A reasonable attitude by regulatory agencies;
3. Canadian/US interaction, especially on the Eastern leg;
4. Additional expenditures (approximately $200 million) for design, engineering and other technical work.

The Federal Government predicted that by the fall of this year conditioning costs, rate of return, pipeline pressure and the like will not only be ruled on but will have been litigated. Additionally, the federal government felt four components are necessary at this time and that it would work toward:

1. Producer participation;
2. State of Alaska equity participation;
3. Expanded partnership;
4. More aggressive assistance from the federal administration.

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES
REP. BILL MILES, CO-CHAIRMAN
REP. C.V. CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

July 3, 1979

GAS PIPELINE UPDATE

ALASKA GAS RESERVES AMPLE BUT INACCESSIBLE

Alaska holds 18.5% of the nation's potential gas supply, but almost 70 percent of the Alaskan reserves probably lie in less accessible offshore areas. The figures were part of testimony offered by Dr. Harry Kent, Director of the Potential Gas Agency, to the House Energy and Power Subcommittee last month.

The Agency estimates that domestic gas supplies are 199 Tcf probable, 399 Tcf possible and 421 Tcf speculative. About 41% of that total potential lies in shallow onshore reservoirs in the lower 48 while Alaska contains some 18.5% or 189 Tcf. Kent noted that the proposed Alaskan land withdrawals would affect some gas development, possibly 10 Tcf of Alaska's potential.

Other witnesses commented on the Alaska gas pipeline situation, with AGA President George H. Lawrence urging speedup of the regulatory process, expedition of the Alaska gas pipeline system, and encouragement of use of Mexican and Canadian gas.

Chaired by Rep. John Dingell, the subcommittee is holding further hearings on natural gas markets, potential oil and gas supplies from Mexico, the Alaska gas pipeline and future Canadian gas exports to the U.S.

JACKSON SAYS "NO" AGAIN TO FEDERAL FINANCING

At a Senate Energy Committee hearing last month, Sen. Henry Jackson reiterated his opposition to federal financing for the Northwest gas pipeline project. Jackson stated, "I am told by the project sponsors that private financing is still possible...I take them at their word and give no encouragement to those who wish that financing will come from the federal Treasury." Jackson also indicated that he may make inquiries into the EXXON gas sales contracts which make gas conditioning costs the buyer's responsibility, contrary to an initial regulatory decision making conditioning costs the gas producers' responsibility.

AGO 532904

GAS PIPELINE UPDATE - 2

FERC FAVORS TRADITIONAL 1260 PSIG PRESSURE PIPELINE

Although a final decision is still to come, it appears that an operating pressure of 1260 psig will be authorized for the Northwest gas pipeline by the Federal Energy Regulatory Commission (FERC). The 1260 psig recommendation by FERC's Alaska Delegate concurs with Northwest's preference for a traditional operating pressure.

The State of Alaska is also conditionally supporting 1260 psig operating pressure if provisions are made for instate use of natural gas liquids as feedstock for petrochemical manufacturing.

Arguing for a higher pressure system have been two North Slope gas producers, Exxon and Arco, and the U.S. Dept. of Transportation. A higher pressure line, testified Exxon, would result in a more fuel-efficient system and a higher throughput capacity, thus allowing a lower cost of service. (Initially Exxon proposed a higher pressure line as a way of eliminating the need for a North Slope conditioning facility. A higher pressure line, such as 1680 psig, would have the capability of transporting heavier gas liquids which the 1260 psig line will not be able to do). The Dept. of Transportation argued that technical and economic data support building a 1680 psig system and having more throughput capacity available would encourage further development and exploration in the North Slope.

Northwest's opposition to the higher pressure systems (1440 psig or 1680 psig) was based on the belief that the testing necessary to validate the higher pressure systems could cause a construction delay of up to two years. Northwest estimated additional carry charges of up to $1 billion would result from such a delay.

FERC agreed that the longer the project is delayed, the more significant the probable cost overruns. Also, the Delegate found, the pressure decision will impact Northwest's ability to obtain private financing, with any departure from a traditional pressure system making investors reluctant to participate in financing.

Still unresolved issues include the disposal of produced butanes (a product of gas conditioning) and the level of CO_2 permissible in the system. The CO_2 level will impact capital costs and operating costs of the conditioning plant and the line itself.

In related testimony, Prudhoe Bay gas producers indicated that the conditioning plant should be located at Prudhoe Bay rather than at an inland location. Sohio and Arco maintained that coastal locations have lower construction costs as they can be served by barges transporting modules for any large facility. ARCO estimated construction costs at 50% higher in Fairbanks or Haines than at the North Slope.

GAS PIPELINE UPDATE - 3

RULING LOWERS COST OF INSTATE USE OF ALASKAN GAS

Future instate use of gas from the Northwest gas pipeline will be less costly because of a federal regulatory decision made recently. The FERC action declares that cost-of-service tariffs for gas taken off inside Alaska will be calculated on a cents per mile basis.

The ruling went against Northwest's proposal for a two-zone tariff, with all charges within one zone to be the same regardless of the distance between the offtake point and the Prudhoe Bay reservoir. Northwest proposed establishing two tariff zones, one from Prudhoe to Delta Junction and the second from Delta Junction to the border. FERC, however, was not satisfied that the proposed zones would "result in equitable distribution of costs."

The cents-per-mile formula lessens the possibility of future struggle between the State and Northwest such as is now occuring over oil pipeline tariffs. Currently Alyeska Pipeline Company wants to charge the same tariff for oil shipped to North Pole as for oil transported to Valdez, another 400 miles south.

The gas tariff formula will also include costs allocated on the heat energy units shipped through the line.

SENATE ENERGY BILL MAY IMPACT GAS PIPELINE PROJECT

Provisions of the Energy Supply Act, a bill under consideration now by the U.S. Senate Energy Committee, may strongly impact the Northwest pipeline project. The bill, testified Northwest President John McMillian at a June 20th hearing, could make the difference between public and private financing of the project.

McMillian's testimony centered on the "regulatory risks" the project is encountering, delays resulting from the federal regulatory process which are creating uncertainty about the project in the financial community. The delays, said McMillian, are adding $3 million a day to project costs or $1.2 billion a year. He took FERC to task for taking 13 months without reaching a final decision on the rate of return for the Alaska segment.

"With the delays we have now, we are looking at '84, '85, a two to three year delay in the project," said McMillian. He affirmed that the financial market could not be approached for project investments until the rate of return and tariff are firmly fixed.

The delay has led to a lower level of sponsor support, McMillian indicated, leaving Northwest facing "some $400 million in development expense before we can start our first stage of construction."

In response to a question from Alaska Senator Ted Stevens about Alaska involvement in the project, McMillian said, "...and we hope to establish a plan to take to the Alaskan people for their referendum type of a vote. What we are asking the State of Alaska for is a billion dollars worth of tax-free bonds. We are also asking the State of Alaska for $500 million of preferred equity in the project."

The Energy Supply Act (S 1308) would expedite non-nuclear energy projects determined to be in the national interest through a speeded-up regulatory process. The bill allows for exemptions from portions of environmental laws and limitations on the rights of environmentalists to challenge the actions in court. Further, it gives the President authority to grant necessary federal permits to a project if any federal agency takes too long to grant the permit.

In a provision which may spark extended comment, the bill also requires the Department of Energy to report to Congress on any state actions which hold up priority projects with recommendations on federal action to override state authorities.

The legislation was co-sponsored by 14 of the 19 members of the Senate Energy Committee. The bill will probably be before the Senate for a vote before the August recess. The House is considering similar legislation.

CANADIAN PREBUILDING PROPOSAL UP FOR HEARINGS

Extensive hearings are underway as Canadian authorities consider the tolls and tariffs to be established for the Canadian portion of the gas pipeline project. An additional series of hearings is to begin at the end of July to consider a Foothills proposal for pre-building portions of the pipeline.

The pre-building proposal depends on the Foothills group gaining Canada's National Energy Board approval to export surplus Alberta gas to the northern U.S. If approved, the exports could begin as early as 1981. Pro-Gas Ltd., a consortium of 26 Alberta gas producers, is supporting the proposal for prebuilding the Canadian and necessary lower 48 portions of the project.

In a separate action the Canadian Northern Pipeline Agency (Canada's equivalent of the Alaska State Pipeline Coordinator's Office) rejected Foothills' environmental studies on the Canadian segment. The Agency called for a second round of hearings, stating that Foothills had not provided adequate information for the Agency to complete its environmental assessment.

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN — REP. BILL MILES, CO-CHAIRMAN
SEN. FRANK FERGUSON — REP. C.V. CHATTERTON
SEN. BILL SUMNER — REP. TERRY GARDINER
REP. JOE HAYES — REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE — MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

July 5, 1979

To: Members of the Joint Gas Pipeline Committee
From: Mary Halloran, Research Analyst MH

A review of Exxon's gas sales contract with Northern Natural Gas shows the following:

The contract is for one-third of Exxon's natural gas from Prudhoe Bay; it's estimated to be 290,000 Mcf/day of gas with a gross heating value of 1060 Btu/cubic foot.

The contract places the responsibility for arranging the gas transportation system (i.e. the gas pipeline, including the conditioning plant) with the buyer, Northern Natural. Northern Natural and the other gas buyers are to have completed contractural arrangements for the transportation system by January 1, 1980. The sales contract may be terminated by March 1, 1980, if arrangements for the gas transportation system are not in place. Also the contract may be cancelled at any time if FERC makes a ruling on the conditioning costs question which is unsatisfactory to either Exxon or Northern Natural.

In addition, the contract calls for Northern Natural and the other gas buyers to get the official certificate of public convenience and necessity by January 1, 1982; otherwise, again Exxon can cancel its sale. The contract calls for the delivery of gas to Northern Natural "no later than January 1, 1986."

The delivery point is "at or near the inlet of the gas conditioning facility," --that is, before conditioning. As buyer, Northern Natural is to provide all facilities at the delivery point for receipt and measurement of Exxon's gas and all downstream facilities necessary for the transportation of such gas.

Before delivery, Exxon will dehydrate the gas and cool it to 120°F, separating oil, condensate and nonhydrocarbon liquids, and objectionable solids from the gas. All such liquids and solids so separated become Exxon's property.

However, natural gas liquids produced through conditioning (not separation) will belong to Northern Natural (except those removed for "efficient pipeline operation.") With three months' notice, Northern Natural can return undisposed natural gas liquids to Exxon for Exxon's use or transport in an oil pipeline.

Still at issue is the level of CO_2 which the conditioned natural gas will contain. The question is important because the CO_2 level not only impacts the cost of the conditioning plant but also affects the pipeline's ability to transport heavier gas liquids, such as butanes.

The sale is subject to the State's right, as lessor, to take its royalty share of gas in kind. The price is the maximum ceiling price allowed by FERC. In

AGO 532908

addition, Northern Natural is to reimburse Exxon 100 percent for all the following state and federal taxes: production, gathering, delivery, sales, severance, excise and other taxes of a similar nature. (There's no reimbursement for ad valorem and general property taxes, income taxes, franchise taxes or other similar assessments).

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES
REP. BILL MILES, CO-CHAIRMAN
REP. C.V. CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

July 25, 1979

To: Members of the Joint Gas Pipeline Committee
From: Mary Halloran, Research Analyst

On June 8, the Federal Energy Regulatory Commission (FERC) issued Order No. 31 establishing the Incentive Rate of Return (IROR) for the Alaska Gas Pipeline. The order is to become final on August 6, 1979.

At a June 21 meeting, the Northwest board of partners voted to withhold further equity support for the project after August 6 (except money necessary to pay off already-incurred debts) and to hold further work on the project in abeyance if FERC fails to change Order 31. The hold on further work will continue, says Northwest, "until such time as the President, the Congress, or the courts correct the errors of Order No. 31."

On July 9, Northwest submitted a formal motion for rehearing the IROR order. The "errors" of the IROR order, according to Northwest's motion, are as follows:

1. The IROR is tied to the March, 1977 cost estimate. Northwest states that the March 1977 estimate does not consider costs such as the estimated $55 million needed to purchase subsoil and other data from Alyeska, the estimated $150 million needed to purchase the Alyeska camps and $4.2 million needed for field programs/ technical studies necessary for the right-of-way.

Governmental indecision, says Northwest, is making a reasonably definite cost estimate impossible. The pipeline's final design, the routing and proximity of the line to the oil pipeline issue, and the terms and conditions of the right-of-way stipulations are matters which affect the cost and which need governmental decisions.

In addition, Northwest states, "It now appears very clear that a reasonable estimate for the Alaskan segment of the project will exceed the March 1977 cost estimate by more than 30 percent." *

Instead of using the March 1977 estimates as the basis for the incentive rate of return, Northwest suggests that FERC use the certification cost estimate to measure cost performance. No certification cost estimate is yet available; once made, it must be approved by FERC before construction may begin.

*The March 1977 costs ranged from $10.5 to $13.9 billion.

AGO 532910

2. According to Northwest, the current IROR order will adversely impact project costs and the cost estimation process by not protecting against cost escalations resulting from force majeure, inflation, field conditions discovered during construction and government-ordered changes.

3. The current IROR order permits only a "negative one-time adjusttment to rate base under certain conditions," an unacceptable procedure from Northwest's perspective.

4. Northwest protested the 8% minimum rate of return on equity, requesting instead a minimum rate of 12 percent.

5. Northwest asked for removal of the portion of the ruling which says that all developmental costs are at risk under all circumstances. The company seeks, instead, a ruling which would not jeopardize their seeking amortization of equity funds in the event of project abandonment.

6. A protest was also lodged against FERC's decision not to allow charges to begin until the whole gas pipeline system is complete and tested, and not to allow equity return until gas flow commences.

7. A protest was also lodged against the possible forfeiture of equity during any period of interrupted service of more than 30 days.

8. Finally, Northwest objected that the IROR order does not establish any legal basis to minimize the risks of future changes in tariffs and service agreements.

FERC has not responded to the motion.

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN — REP. BILL MILES, CO-CHAIRMAN
SEN. FRANK FERGUSON — REP. C.V. CHATTERTON
SEN. BILL SUMNER — REP. TERRY GARDINER
REP. JOE HAYES — REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE — MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

August 2, 1979

REPORT ON INFORMAL MEETING OF THE JOINT GAS PIPELINE COMMITTEE
By Mary Halloran, Research Analyst

On July 31, 1979, newly appointed Federal Inspector John Rhett met with members of the Joint Gas Pipeline Committee in Anchorage. The discussion covered several items:

STATE HELP FOR THE PROJECT -- Rhett stressed that one major thing the State can do is "get the point across that Northwest is the only game in town." An All-Alaska line is not a possibility. Another aid is the State's "one window" permit approach being headed by Chuck Behlke, new State Pipeline Coordinator.

FEDERAL COMMITMENT -- The project is the only energy project specifically mentioned by President Carter in his recent energy speech. The federal government, says Rhett, is moving more quickly on several regulatory decisions still pending. The Incentive Rate of Return issue is to be finally decided August 8. The gas conditioning costs question is to be wrapped up September 1 "except for legal action." And the Carter-requested meeting with producers to discuss debt financing overrun guarantees will take place soon. The State will not be included among the producers in that instance, Rhett indicated.

FINANCING -- Rhett stressed the federal government's continued conviction that the line will be privately financed. "We're not convinced today-- we may be a month from now -- that it cannot be privately financed." Talk of a need for federal guarantees may be a self-fulling prophecy, Rhett suggested, with a need for federal guarantees created by people saying there is a need for federal guarantees.

In regard to possible state financing, Rhett responded, "We'd love to see it." The proposed state revenue bonds are "probably pretty well expected in the financial community." It would, said Rhett, "put a shock through the system" if the bonds are not issued. However, he added, no federal/congressional action has been taken on the change in the IRS Section 103 code change necessary for the state bonds to be issued. The request for a change in the code "has never been asked. It really has not been formally presented within the federal government."

A state equity investment would be a "much tougher" issue, Rhett said, noting that equity investments must be "prudent" and involve major philosophical questions.

"Any financial occurring at this time is a conditional form of financing...You're not dead certain whether you're buying a pig in a poke," said Rhett.

REPORT ON INFORMAL MEETING OF THE
JOINT GAS PIPELINE COMMITTEE - 2

PROJECT TIMELINE --Preliminary financing must be arranged by December 31, 1979, Rhett stated. "I feel that by December 31 this year, it's either going to be positive or we've got real problems and we're going to slip another year." Asked if Alaska financial commitment was also necessary by December 31, Rhett replied, "What we're talking about this fall is not that tight a package." Alaska, he indicated, would not lose out by making a decision about state participation in project financing at a later date.
Other project dates, as outlined by Rhett, are as follows:
Preliminary financing by December 31, 1979.
Northwest application for certification by June, 1980.
Federal Energy Regulatory Commission processing of the certification application will take one year, with an additional five months allowed for litigation, bring completion of the certification process to October, 1981.
Design on the Alaska segment will be seventy percent done in 1982. Until then, Rhett said, no completely good financing estimate for the project will be available. By that time Northwest will have spent an estimated $400 million.

FEDERAL FINANCING -- In response to questions about the federal government's reluctance to participate in project financing, Rhett said that consideration of federal guarantees raises both philosophical and monetary problems. "You start guaranteeing these bonds for natural gas, what does that do -- downgrade every other federal bond for natural gas? Does this mean every major project has to have federal guarantees?"

TECHNICAL ISSUES --The proximity issue (how close the project will be constructed to the existing Alyeska oil pipeline) will ultimately be resolved, Rhett said. "There are some knotty issues there--technical and legal, particularly liability." By federal law, Alyeska has unlimited liability for the oil pipeline.

OTHER ITEMS -- Rhett regarded as "very controversial" reports indicating that early gas withdrawals may damage ultimate oil recovery at Prudhoe Bay. In regard to the Canadian segment, Rhett reaffirmed the federal support for that project, although he admitted "some stagnation" in Canadian progress. Promising an open exchange of information, Rhett plans to headquarter in D.C. until after the Candaian segment of the line is built.

Present at the meeting were Sen. Mike Colletta, Rep. Bill Miles, Sen. Bill Sumner, Rep. Chat Chatterton, Rep. Joe Hayes, Attorney General Av Gross, and State Pipeline Coordinator Chuck Behlke.

For the Governor's Task
Force on Gas Conditioning
September 20, 1979

INSTATE OPTIONS FOR USE OF NORTH SLOPE NATURAL GAS

Per the request of Joint Interim Gas Pipeline Committee co-chairmen, Sen. Mike Colletta and Rep. Bill Miles, this paper outlines the instate options for use of North Slope natural gas and the policy questions inherent in those options.

INSTATE OPTIONS

Several options exist for the possible use of North Slope natural gas instate, including new industrial development, direct residential and commercial use, electrical power generation, and expansion of existing industry. Among the possibilities are the following:

1. New industrial development

A. Gas conditioning plant at Prudhoe Bay, with a gas liquids line from Prudhoe to Fairbanks;

B. Gas conditioning plant at Prudhoe Bay, with a gas liquids line from Prudhoe to tidewater;

C. Gas conditioning plant at Prudhoe Bay, with a gas liquids line from Prudhoe to tidewater, and a petrochemical complex at tidewater;

AGO 532914

D. Gas conditioning plant at Prudhoe Bay, with a gas liquids line from Prudhoe to the Interior, and a petrochemical complex in the Interior;

E. Gas conditioning plant at Prudhoe Bay, straddle plant in the Interior, with a gas liquids line from Interior to tidewater;

F. Gas conditioning plant at Prudhoe Bay, straddle plant in the Interior with a petrochemical complex in the Interior;

G. Minimum conditioning facility at Prudhoe Bay, gas conditioning plant in the Interior, with a petrochemical complex in the Interior. (The current plan is for a gas conditioning plant at Prudhoe Bay with gas liquids transported in vapor stage through the gas pipeline).

2. Direct residential and commercial use

A. Takeoff taps and distribution lines for residential and commercial use for communities along the gas pipeline route;

B. Distribution system for delivery of gas to the entire Railbelt area and to communities along the gas pipeline route;

C. Small scale turbo-expander plants to separate propane and butane from the gas stream for direct instate consumption, primarily for heating.

3. Electrical power generation

A. Generation of electricity from gas on the North Slope for transmittal to the entire Railbelt area;

B. Generation of electricity from gas at specific locations along the gas pipeline route, including Fairbanks;

C. Trade of Prudhoe Bay royalty gas for Cook Inlet gas, which then could be used by existing utilities for electrical generation in Southcentral.

4. Expansion of existing industry

A. Expansion of the existing ammonia and urea industry;

B. Other agriculture-related uses such as grain drying, controlled environment enterprises and greenhouse operations.

POLICY ISSUES AND RECOMMENDATIONS

Each of the options for instate use of natural gas has inherent policy implications. Choosing to pursue one course of action may, in fact, preclude active consideration of other instate use options, due to a quantitatively limited amount of natural gas.

The first obvious policy consideration, then, and probably the most important, is how to use the resource to benefit the maximum number of residents on a long-term basis. Although there has been considerable discussion about some of the options, an up-to-date analysis comparing the costs and benefits of the different options is not available. Nor is there a current comparative analysis of the economic, legal and political feasibility of the various options.

The option which has captured public attention at the moment is new industrial development, either a gas liquids line or a large-scale petrochemical complex, or some combination of the two. Although the actual industrial activity would presumably be a matter for private enterprise, the choice to help promote new petrochemical industry carries with it both potential benefits and risks to the State.

In recent discussions, the potential benefits to the State or to certain regions of the State have been well defined. Longterm employment, stable tax bases and spinoff business opportunities lead the list. Not so well defined at this time are the possible risks. For example, if the State choose to pursue modification of the Federal Energy Regulatory Commission (FERC) order regarding pipeline pressure, what are the chances of predisposing FERC to act contrary to the State's interest on other issues, such as the State's right to withdraw methane at any time or the CO_2 standard for the gas stream? Or, to take another example, could the State be forced to make an equity investment, which it might not consider a prudent business investment, in the gas pipeline project in order to gain the opportunity for instate petrochemical industry? In other words, what tradeoffs would the State have to make to ensure, as much as possible, that a petrochemical industry would have the highest odds for successful operation in Alaska?

In addition to a thorough analysis of the possible legal and political tradeoffs, the State also needs to closely examine the economic benefits and risks in new petrochemical development. A review of the research on the feasibility of such industry in Alaska reveals that most consider it marginal, although it may be more attractive in the future. Given the still inconclusive economics, is there a risk that Alaska could be put in a position where a state subsidy of petrochemical industry is necessary? On the other hand, what incentives could the State offer to promote petrochemical industry on a self-sustaining basis?

The extent to which a petrochemical project is feasible can be measured, of course, by exploring the free market support for such a venture. With the estimated capital investment for an Alaska petrochemical system quite high, only very large scale companies would appear to be able to handle the construction and operation. What interest do the major petrochemical firms, such as Dow, Dupont or Union Carbide, have in industry development in Alaska? Open and direct discussions with the major firms, initiated by the State, could explore whether interest exists and under what conditions the firms would consider investment here.

Another mechanism could also be used to guage commercial interest in instate petrochemical development --- promotional contracts for the sale of State royalty gas. The contracts, as now drafted, propose to sell the State's royalty gas on the condition that the buyer construct and operate processing facilities instate. A further stipulation is that the gas, and any products or liquids derived from the gas, may not be sold outside Alaska unless they are unable to be sold at a reasonable price for use or consumption within the State. Opening the contracts up for consideration by the private market could enable the State to examine commercial interest.

At the same time, direct discussions, also initiated by the State, need to take place with the gas producers on the possibility of trading the State's share of methane for the producers' gas liquids. Analysis to date indicates that Alaska's royalty share of the North Slope natural gas liquids is not sufficient for feasible petrochemical development. These discussions should take place prior to the next legislative session.

The State faces other policy considerations in addition to the direct economic, legal and political feasibility of petrochemical development. The Alaska economy rests solely on an oil and gas basis which a petrochemical complex would fail to diversify. An assessment is needed of whether promotion of petrochemical industry

would hinder the State's ability to encourage other more diversified industry. A further consideration is how the development of a gas-based petrochemical complex will impact the Alpetco project. Although the products produced from the two facilities would presumably not conflict in the marketplace, would there be competition for available capital, resources and supplies?

In short, the issue of new petrochemical development is uncertain and cloudy. Although the odds against successful new petrochemical industry appear to be heavy, the potential longterm benefits are substantial enough that decisions must be made on more information than is currently known -- first-hand information that can be made available only through direct discussions with both the gas producers and the major petrochemical firms. The discussions should be initiated by the State immediately.

It is clearly time for the State to get a comprehensive, comparative and realistic picture of the options for instate use of natural gas. Regardless of the choice or choices made for further State action, it is also clear that Alaskans feel strongly that any project which moves all the North Slope natural gas out of the State is not in Alaska's best interests.

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA
CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES

REP. BILL MILES
CO-CHAIRMAN
REP. C.V. CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR

EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

October 15, 1979

MEMO

TO: Members of Joint Gas Pipeline Committee

FROM: Mary Halloran MH, Research Analyst

Enclosed are copies of recent reports on the possible effects of the State issuing up to one billion dollars in revenue bonds for the Northwest gas pipeline project.

AGO 532921

nuveen
John Nuveen & Co. Incorporated 209 South LaSalle Street, Chicago, Illinois 60604 (312) 621-3000

RECEIVED
SEP 28 1979
OFFICE OF THE COMMISSIONER

September 24, 1979

Thomas K. Williams
Commissioner
Department of Revenue
State of Alaska
Pouch "F"
Juneau, Alaska 99811

Dear Tom:

In our capacity as financial advisor to the State of Alaska, you have asked us to assess the effect on the State's general credit standing of a $1 billion tax-exempt revenue bond issue for the Alaska Natural Gas Pipeline. In responding to this request, we have assumed that Congress will enact the necessary amendments to the Internal Revenue Code to assure that interest on the bonds will be exempt from Federal income tax.

A revenue bond financing of this magnitude would have no significant effect on the general credit of the State, provided the bonds do not create any direct or contingent liability against State revenues and the bonds are adequately secured by a combination of pipeline revenues and the financial resources of the other participants. However, the State's credit standing could be altered to the extent that the bonds benefit from security features similar to the following:

1) A full faith and credit guarantee of the State,

2) A guarantee by the Permanent Fund,

3) A "make up" provision to restore deficiencies in reserve accounts, or

4) An obligation to issue or purchase completion bonds.

If the State were to provide such additional security, the nature and magnitude of any impact on Alaska's credit would be a function both of the economic and financial strength of the pipeline project and of the extent to which other participants have assumed risks associated with the project, including:

1) Completion delays

2) Cost overruns

3) Start-up difficulties and failure to achieve design performance,

4) Casualty losses,

5) Adverse political or regulatory decisions.

We understand that project participants have not at this time provided appropriate assurances regarding these risks. When such assurances are forthcoming we would be pleased to assist your office in evaluating the proposed apportionment of project risks and to advise you of their implications for the State's financing activities.

If we can be of further assistance, please don't hesitate to call upon us.

Sincerely,

Tony Dean

Anthony T. Dean
Asst. Vice President

ATD:Lmc

Dillon, Read & Co. Inc.
46 William Street
New York 10005

September 19, 1979

Mr. Thomas K. Williams
Commissioner
Department of Revenue
State of Alaska
Pouch SB
Juneau, Alaska 99811

Dear Tom:

You have asked whether the issuance of $1 billion tax-exempt revenue bonds by an Alaskan state authority for financing a portion of the Alaskan segment of the Alaskan Northwest Natural Gas Transportation System would have an adverse effect on the State's credit.

Based on our knowledge of the tax-exempt bond market, it is our opinion that so long as the bonds are truly revenue bonds, that is, the revenues to service the bonds will come strictly from funds generated from the use of the project, and that no tate sources will be pledged to the repayment of the bonds, such bonds will not have an adverse effect on the State's credit. We would note, however, that the ability of the authority to issue and market such bonds would appear subject to several threshold questions, including, among others, the following:

1. The Congress would have to pass legislation providing for exemption from Federal income taxes of the interest paid on the bonds. Under current law, bonds so structured would not be tax-exempt.

2. Financing commitments for all other portions of the gas pipeline including the Canadian segment, would have to be in place.

3. A creditworthy entity would have to agree either to pay off the bonds in the event that the project or any related critical element is not completed or, alternatively, to provide the necessary funds to complete any such uncompleted element.

4. There would have to be a reasonable expectation that revenues from the project would be sufficient to pay all operating costs, scheduled debt service on the revenue bonds and to provide a reasonable margin of revenues in excess of operating costs and debt service requirements.

Needless to say, the above does not represent an exhaustive list of the key requisites to successful financing. However, at a minimum these considerations would have to be dealt with fully before any financing by the authority could be contemplated.

Please let us know if we can be of further assistance.

Very truly yours,

Robert A. Gerard
Senior Vice President

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN
REP. BILL MILES, CO-CHAIRMAN
SEN. FRANK FERGUSON
REP. C.V. CHATTERTON
SEN. BILL SUMNER
REP. TERRY GARDINER
REP. JOE HAYES
REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

October 16, 1979

TO: Members of the Joint Gas Pipeline Committee

FROM: Mary Halloran MH, Research Analyst

RE: Gas Sales Contracts

With Atlantic Richfield's recently announced gas sales, all Prudhoe Bay gas (except the State's royalty share) is now covered by gas sales contracts, tentative as those contracts may prove to be. This paper reviews which companies have purchased the gas and whether the purchasers are members of the current Northwest partnership.

The total estimated volume of Prudhoe Bay gas is about 26 Tcf, or 2.4 Bcf/day. Of that total, ARCO owns 31.5%; EXXON, 31.5%; SOHIO, 23.5%; and State of Alaska, 12.5%.

ARCO Sales

ARCO has sold its 31.5% to six companies:

1. Pacific Interstate Transmission (a subsidiary of Pacific Lighting) - 33% of ARCO's share;
2. United Gas Pipeline Co. - 15% of ARCO's share;
3. Texas Gas Transmission Corp. - 12% of ARCO's share;
4. Panhandle Eastern Pipeline Co - 20% of ARCO's share;
5. Texas Eastern Gas Pipeline Co. (subsidiary of Texas Eastern Transmission) - 10% of ARCO's share; and
6. Transwestern Pipeline Co. (subsidiary of Texas Eastern Transmission) - 10% of ARCO's share.

EXXON Sales

EXXON has sold its 31.5% to three companies:

1. Pacific Gas and Electric - 33 1/3% of EXXON's share;
2. Michigan Wisconsin Pipeline - 33 1/3% of EXXON's share;
3. Northern Natural Gas - 33 1/3% of EXXON's share.

SOHIO Sales

SOHIO has sold its 23.5% to two companies:

1. Northern Natural Gas - 33 1/3% of SOHIO's share; and
2. Columbia Gas Systems, Inc. - 66 2/3% of SOHIO's share.

The State of Alaska has not entered into sales contracts for its 12.5% share of the total volume.

Who Owns How Much

As a result of the tentative sales, the ownership of Prudhoe Bay natural gas rests with the following gas transmission companies:

Company	Percentage of total volume (rounded figures)
*Northern Natural Gas	18.3 %
Columbia Gas Systems, Inc.	15.5 %
Michigan Wisconsin	10.5 %
*Pacific Gas & Electric	10.5 %
*Pacific Interstate Transmission (a subsididary of Pacific Lighting)	10.5 %
*Panhandle Eastern Pipeline	6.3 %
*United Gas Pipeline Co.	4.73 %
Texas Gas Transmission Corp.	3.78 %
Texas Eastern Gas Pipeline Co. (a subsidiary of Texas Eastern Transmission)	3.15 %
Transwestern Pipeline Co. (a subsidiary of Texas Eastern Transmission)	3.15 %

The companies marked with an asterik (*) are current partners in the Northwest Natural Gas Transportation Co., sponsors of the Alaska segment. Five of the six partners have entered into gas purchase contracts for North Slope gas; Northwest Energy Co. has not entered into such a contract nor is it expected to. Those companies which have entered contracts but which have not become partners in the Northwest Transportation Co. are Columbia, Michigan Wisconsin, Texas Gas, and two subsidiaries of Texas Eastern Transmission, Texas Eastern Gas Pipeline Co., and Transwestern Pipeline Co.

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES
REP. BILL MILES, CO-CHAIRMAN
REP. C.V. CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 278-4340

October 26, 1979

GAS PIPELINE UPDATE

The Joint Gas Pipeline Committee continues to receive much informal and formal information about the progress of the gas pipeline project. This paper reviews some of the information received since the publication of the Joint Gas Pipeline Committee's Mid-Interim Report on October 10, 1979.

GAS PIPELINE FINANCING

1. Report to the Bonding Authority by John Nuveen & Co.

In a September 24, 1979, letter to Bonding Authority Director Tom Williams, Nuveen Co. indicated that a $1 billion tax-exempt revenue bond issue could affect the State's general credit if it were accompanied by security features similar to the following:

(1) a full faith and credit guarantee of the State;

(2) a guarantee by the Permanent Fund;

(3) a "make up" provision to restore deficiencies in reserve accounts; or

(4) an obligation to issue or purchase completion bonds.

AGO 532928

With no such features and provided the bonds are secured by pipeline revenues and the financial resources of other participants, the revenue bond financing would not significantly affect the State's general credit.

However, Nuveen pointed out that if the State provided such additional security, impact on Alaska's credit would depend on the project's financial strength and "the extend to which other participants have assumed risks associated with the project." Those risks include: completion delays; cost overruns; start-up difficulties and failure to achieve design performance; casuality losses; and adverse political or regulatory decisions. "We understand that project participants have not at this time provided appropriate assurances regarding these risks," concluded Nuveen.

2. Report to the Bonding Authority by Dillon, Read & Co.

In a September 19, 1979, letter to Bonding Authority Director Tom Williams, Dillon & Read concluded that so long as the proposed $1 billion tax-exempt revenue bonds are "truly revenue bonds," they will have no adverse effect on the State's credit. "True" revenue bonds have no State sources pledged to repayment of the bonds; and revenues to service the bonds "will come strictly from funds generated from use of the project."

Dillon & Read noted at least four conditions which need to be met to enable the Bonding Authority to issue and market revenue bonds:

(1) Passage of federal legislation providing for tax-exempt status for such bonds;

(2) Financing commitments for all other portions of the project, including the Canadian segment, in place;

(3) Agreement by a creditworthy entity either to pay off the bonds in the event the project is not completed, or, to provide the funds necessary for completion; and

(4) Existence of a reasonable expectation that project revenues would be sufficient to pay all operating costs and debt service, and provide a "reasonable margin" of revenues beyond the operating costs and debt service requirements.

TECHNICAL AND ENVIRONMENTAL ISSUES

1. "Status of Technology: Alaska Natural Gas Transportation System" by the Arctic Environmental Information and Data Center, October, 1979

In brief, the major technical issues remain unsettled, including the central issue of proximity of the gas pipeline to the TAPS oil pipeline. The lack of resolution will impact both the project's completion date and project sponsors' efforts to obtain financing.

The lack of cooperative effort by the involved parties and the project's "sheer complexity" leave the identification of an alignment for the gas line unresolved, despite the Department of Interior's "provisional approval" last summer. "The potential for physical damage to TAPS during construction " remains a strong concern of TAPS owners.

On September 10, 1979, Northwest released an "Outline-Pipeline Design Process," an "extremely optimistic viewpoint." Upon examination of the proposed Northwest schedule and activities, the Arctic Environmental Information and Data Center (AEIDC) noted,

> "Northwest Alaskan is just now beginning to address some of the real problems that must be resolved before they receive approval on final design and begin construction...."

Thus, the projected 1984-85 completion date is "unrealistic." Instead, AEIDC estimates that the gas deliveries will be at least a year or two later than currently projected. The lag in resolving technical problems will impact project financing:

> "Cost of the project cannot be determined with any certainty until the proximity question is resolved. Such factors as pipeline thickness, quantities of gravel required, construction schedules, and the question of liability between TAPS and ANGTS must also be resolved."

The lag appears not to stem from disinterest in the technical questions on the part of Arctic scientists. Papers presented at the 30th Alaska Science Conference this fall dealt extensively with building a chilled gas pipeline in an arctic environment. The AEIDC comments,

> "The science and technology of construction and other factors of energy development in an arctic environment are certainly moving forward. The degree to which Northwest Alaskan is participating with the science and government community in this endeavor, however, appears to be minimal, at best."

The report reviews nine areas of current studies and testing: (1) burst tests; (2) blasting tests; (3) frost heave testing; (4) work pad considerations; (5) hydrology; (6) proximity to TAPS; (7) risk analysis; (8) design pressure; and (9) corrosion. Other administrative and political decisions may also impact the project's completion date. Three such upcoming items include: (1) GAO report on the economics and other matters; (2) reimbursement of costs for the permitting process; and (3) industry's planning and other work relating to the gas conditioning plant.

Gas pipeline planning to date "is fragmented and ill-planned, both by government and industry." The establishment of the office of Federal Inspector should improve matters, but many problems may have to be resolved before that office becomes an effective

operation. Thus, AEIDC recommends that the State address major issues such as cost reimbursement, gas conditioning plant, and the pipeline design process in the Joint Federal-State Cooperative Agreement or in other ways.

In general, North Slope gas is desirable. The questions are when it will be delivered and at what cost. International scientists apparently believe that a chilled gas line can not be buried except at great cost, although a buried line is what Northwest proposes. In conclusion, AEIDC states,

> "The development of the necessary technology for the design and construction of this project has not kept pace with the rhetoric of the statements by Northwest Alaskan that they can complete the project efficiently and in an acceptable way (both technically and environmentally) with the stated time frames."

INSTATE USE OF NORTH SLOPE NATURAL GAS

1. "Preliminary Analysis of Markets for Gas Distribution to Pipeline Corridor Communities" by Northwest Alaskan Pipeline Company, May, 1979 (released July 27, 1979)

The Northwest Alaskan report concludes from its preliminary analysis of instate markets that use of North Slope natural gas for heating and electrical generation in the Fairbanks area appears economically feasible. Similar use of the gas

in other pipeline corridor communities may be only marginally economical. However, the report does not include any analysis of the effects of the recent OPEC oil price increases. Northwest reiterated its support for establishing gas taps along the pipeline corridor, suggesting that the next step is "an economic feasibility analysis by the State." The price of gas depends on three factors: (1) field price; (2) pipeline transportation costs; and (3) distribution costs. The distribution costs are likely to be the major cost for any instate use.

Fairbanks Area Markets: If electrical power generation is part of the Fairbanks area demand, then, the report suggests, an adequate market for natural gas exists in the area. Electrical generation at Ft. Wainwright and Eielson Air Force Base is expected to remain coal-based. Northwest found "a strong interest in the private sector" in natural gas distribution "provided the gas can be competitively priced relative to other fuels."

Delta Area Markets: Northwest identified these possible markets: grain drying complex; space heating for Ft. Greeley, Delta Junction and Big Delta; and electrical generation for the Delta area. Promoters of Delta agricultural growth are interested in using natural gas, and two of the three proposed sites for a grain drying/elevator complex are "only 600 feet from the pipeline right-of-way."

Tok Area Markets: Possible space heating and electrical generation use exists in the Tok area. "The use of natural gas to generate electricity appears more promising than home heating distribution."

The Northwest report briefly discusses the factors affecting the economic feasibility of local gas distribution systems. The "load," the volume of demand and whether it is sufficient to pay for delivery costs, is the key economic factor. The delivered gas price cannot be more than the price of No. 2 home heating oil on a BTU-equivalent basis if it is to be economically attractive.

The high volumes of gas required for Alaskan winter heating would leave the system operating "at much less than capacity for the remainder of the year." Without local industrial customers to take up the offseason load, the corridor gas distribution systems "would face severely low load factors (that) would greatly increase their cost per million Btu delivered."

Another factor in instate gas use would be the timely conversion of existing heating systems to gas usage, and the economics of making the conversions. The report also indicates that additional industrial use, such as electrical generation and grain drying, improves the economics of pipeline corridor gas distribution systems. The report concludes, however, that in communities other than Fairbanks, "economic feasibility is marginal."

In a cover letter accompanying the report, Northwest noted, however, the following:

(1) The report does not include any economic analysis of the effects of the recent OPEC oil price hikes (or projected growth in oil prices over the next few decades);

(2) The report does not anticipate any major new industrial markets, except the Delta grain drying complex;

(3) The report does include the use of gas for electrical generation as it appears that the Federal Energy Regulatory Commission may allow such use for power generation in lieu of heating oil use.

It should also be noted that the report examines only the use of natural gas through direct taps and distribution systems, not the potential uses of such gas-based products as propane for instate heating.

GAS SALES

With Atlantic Richfield's recently announced gas sales, all Prudhoe Bay gas (except the State's royalty share) is now covered by sales contracts, tentative as those contracts may prove to be. The total estimated volume of Prudhoe Bay gas is about 26 Trillion cubic feet, or 2.4 Billion cubic feet/day. Of that total ARCO owns 31.5%; EXXON, 31.5%; SOHIO, 23.5%; and State of Alaska, 12.5%.

As a result of the three producers' tentative sales, the Prudhoe Bay natural gas should go to the following gas transmission companies: *Northern Natural Gas, 18.3%; Columbia Gas Systems, Inc., 15.5%; Michigan Wisconsin, 10.5%; *Pacific Gas & Electric, 10.5%; *Pacific Interstate Transmission, 10.5%; *Panhandle Eastern Pipeline, 6.3%; *United Gas Pipeline Co., 4.73%; Texas Gas Transmission Corp., 3.78%; and Texas Eastern Gas Pipeline Co. and Transwestern Pipeline Co. (both subsidiaries of Texas Eastern Transmission), 3.15% each. The State has not entered into sales contracts for its 12.5% share of the total volume.

Those companies starred with an asterisk (*) above are current partners in the Northwest Natural Gas Transportation Co., sponsors of the Alaska segment. Of the pipeline project partners, only Northwest Energy Co. has not purchased North Slope gas, nor is it expected to. Those companies which have agreed to purchase North Slope gas but which have not become Northwest partners are Columbia, Michigan Wisconsin, Texas Gas, and the two subsidiaries of Texas Eastern Transmission.

This report was prepared on behalf of the Joint Gas Pipeline Committee by Mary Halloran, Research Analyst.

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES
REP. BILL MILES, CO-CHAIRMAN
REP. C.V. CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

November 9, 1979

TO: Members of the Joint Gas Pipeline Committee

FROM: Mary Halloran MH, Research Analyst

Enclosed is a copy of a November 6 report by Chomski and Haggart regarding the Canadian segment of the proposed Northwest gas pipeline project. In brief, it appears that the Canadian government will hold up its approval of prebuilding the Eastern Leg (Northern Border) segment of the gas pipeline "until the Board is satisfied that...North Slope gas will actually flow."

Also yet to be resolved in Canada is the Indian land claims. The Indian groups appear ready to exert pressure to have the issue resolved prior to gas pipeline construction, following the often cited example of Alaskan natives and the oil pipeline. The issue is complicated by questions of jurisdiction of the various parties, with possible conflict between the provincial and federal governments over which has the authority to settle with the Indian groups.

Despite the unresolved issues in Canada, Canadian financing "prospects should be fairly solid," as the project has extensive national backing. Rumors of the "fragility" of Canadian financing appear unfounded.

Chomski and Haggart also describe the recent EXXON proposal, remarking that it "does little to clarify the financing outlook for the pipeline." It, in fact, places the Carter administration in a difficult spot as it is designed to pass conditioning costs on to the American consumer. "Seen in the context of an upcoming election, it is difficult to predict what choice the Carter Administration might make between having producer financing available and enduring the wrath of consumer and liberal advocates."

Chomski and Haggart conclude that the critical time for financing the project, and for making a decision about State participation in the project, continues to be this coming spring. However, they also add, "it remains very questionable whether this project will succeed during 1980." Most likely, they conclude, will be renewed activity and a "possible reformulation of the project" after the 1980 elections. Alaska, in the meantime, may find itself the subject of strong Carter administration pressure to participate in the project.

LAW OFFICES
BIRCH, HORTON, BITTNER AND MONROE
4400 JENIFER ST., N. W. - SUITE 300
WASHINGTON, D. C. 20015
(202) 244-4250
TELEX 9-89-2591

713 W. FOURTH AVE., SUITE 206
ANCHORAGE, ALASKA 99501
(907) 279-9403
TELEX 25-356

1200 AIRPORT HEIGHTS DRIVE
ANCHORAGE, ALASKA 99504
(907) 279-9501

751 OLD RICHARDSON HWY., SUITE 340
FAIRBANKS, ALASKA 99707
(907) 452-1666

130 SEWARD STREET, SUITE 314
JUNEAU, ALASKA 99801
(907) 586-2890

MEMORANDUM

To: JOINT INTERIM PIPELINE COMMITTEE

Date: November 6, 1979

Canada

The National Energy Board is continuing its consideration of applications to export surplus Canadian natural gas to the continental United States. This surplus gas will be the basis for the "pre-build" sections of the Alaska Natural Gas Transportation System. All parties to the proposed system agree that early approval of the pre-build segments will provide significant assistance in terms of project financing, both by spreading out construction costs (and hence, capital market effects) over a longer period of time, and by providing early cash flows to project partners.

The NEB, however, has been moving slowly on the approval of gas exports. The Canadians have been frank that their foot-dragging is due to a perceived lack of progress on the U.S. side of the project and that they have no intention of making major commitments of gas sales to the United States as long as the ability of the U.S. side of the gas project to be successfully completed remains in question. There are two basic steps the Energy Board must take before gas can flow to the United States:

1. Approval of gas exports to the United States by selecting among competing company applications for such exports. (The identity of competitors does not seem to be dispositive with respect to the export issue.)

2. Approval of construction of necessary Canadian facilities to transport the export gas.

The approval of facilities construction on the Western Leg involves relatively minor looping operations, while on the Eastern Leg, more extensive pipeline construction is necessary. There are also significant volume differentials between the two systems, with projected throughput of the Western Leg being 200 mcf per day, while that of the Eastern Leg is 800 mcf per day.

The current estimate is that the Energy Board will approve gas exports for both the Eastern and Western Legs of the project by the end of November. However, the requisite facilities approval will not be forthcoming for the Eastern Leg until the Board is satisfied that progress on the American side of the project indicates a high likelihood that North Slope gas will actually flow. Thus, the Canadian strategy appears to be approval of the Western Leg with its relatively small construction requirements and its relatively smaller throughput, while continuing to hold the Eastern Leg facilities hostage until the U.S. side of the project makes further progress. The Canadian's prime concern is the inability of the project to attract financial support. It is illuminating to note that the Energy Board held hearings on the financing difficulties being encountered on the U.S. side on October 29, 1979. The hearings also included discussion of the possibility of the need for U.S. Government guarantees, as well as FERC's authority to enforce purchase requirements upon local utilities.

As Rhett indicated in our meeting, the Canadians are seeking "assurances" with respect to the completion of the Alaska segment of the line before going ahead in any major way with the pre-build segments. However, the Ottawa government is still vague as to what such assurances might entail. In our judgment, the Canadians will remain vague on this issue to appear flexible and to avoid giving U.S. bureaucrats a stationary target. It seems most likely that the Canadians will reach an independent determination with respect to the financing status of the pipeline sometime next spring and will proceed accordingly.

The major potential obstacle to the project on the Canadian side is the unresolved question of Indian land claims along the pipeline right-of-way. This issue has been quiet recently, because the change in Canadian governments resulted in a break-off of talks between the two groups while the Clark government developed its policy with respect to land claims settlement. Reportedly, the Clark position was originally designed to be "tougher" than that pursued by Trudeau. However, recent indications by the Council of Yukon

Indians (among others) are that they are ready and willing to block any pipeline -- oil or gas -- if construction is attempted before the land claims issue is settled. The Indian groups in Canada have been extremely explicit regarding what they view as the parallel between the proposed gas pipeline and the Trans-Alaska Oil Pipeline. Specifically, they note that settlement of Alaska Native land claims was speeded, and possibly was entirely due to the fact that the Alaska Native groups were capable of holding the pipeline hostage to legal action for an unacceptable period of time. The Canadian Indians believe that a similar strategy will serve them well, and according to the Canadians, the CYI is well prepared to go to court (to the extent of having briefs drafted) if the government should attempt to move ahead on the pipeline prior to a land claim settlement. In addition, the Indian groups have threatened (at least informally) to pursue judicial "guerilla action" against Canadian gas transmission companies in Western Canada. Such efforts would consist of attempting to tie up company activities on minor zoning regulations, environmental regulations, etc., to provide added impetus for the government to settle.

Apparently, the level of preparation among the Indian groups and their willingness to take drastic action to halt or delay pipeline construction has impressed Clark's government. There has been a fairly significant change in the attitude in Ottawa toward a settlement and as of the end of last week, after three days of intensive talks between Indian groups and the federal government, the situation appears to be "very much in hand". While this sounds suspiciously like the bland assurances available from Jack Rhett, it is at least encouraging to note the Canadian government's realization of the enormous potential for the land claims issue to imperil project success. A further complication exists in terms of the jurisdiction of the various parties to land claims issues. The basic land claims problem exists in the Yukon Territory and in British Columbia. The Yukon land settlement appears to be purely a federal question, although a delay in the settlement could cause jurisdictional problems since Clark has promised to move the Yukon to provincial status. In British Columbia, there is apparently a jurisdictional dispute between the provincial and federal governments regarding authority to settle the land claims issue. It is possible that a major dispute between Victoria and Ottawa on this issue could involve further delay.

FRAGILITY OF CANADIAN FINANCING

We also were requested to examine the possibility that the Canadian side financing is relatively uncertain, or "fragile", as opposed to the more common belief that Canadian financing will be no problem. It is difficult to come up with a precise response as to how solid Canadian financing is because the consortium has not yet gone to the financial markets with a firm proposal and tried to finance it. However, we find no factual basis for the rumors that financing may be more difficult in Canada than is now supposed. While the final terms and conditions of any financing package cannot be determined as yet, it appears that they should be favorable to Foothills. More importantly, when one examines the financial strength behind the Canadian side of the line, it becomes increasingly clear that their financing prospects should be fairly solid. The Canadian portion of the line is backed by the three largest Canadian pipelines, the State Oil Company of Canada, the largest private oil company of Canada, the British Columbia Government (and its cash-rich Resources Investment Corporation), and the Alberta Government which is seeking desperately to find ways of investing its Heritage Fund. Moreover, there is only significant risk in the Yukon segment of the line which constitutes slightly less than $2 billion of the $5.5 billion Canadian capital cost segment. When one adds to these fundamentals the realization that some of the Canadian line would be financed during the pre-build period, while other parts would be financed afterwards, thus spreading out the burden on the financial markets, we can only conclude that the "fragility rumor" appears unfounded.

U.S. FINANCING DEVELOPMENTS

Exxon's recent proposal to the United States Government does little to clarify the financing outlook for the pipeline. Exxon's proposal, ostensibly made on its own behalf, assumes participation by Arco and Standard Oil of Ohio. Both of these companies have made preliminary comments indicating approval of the general thrust of Exxon's concept. Basically, the Exxon proposal involved:

1. That the three major North Slope natural gas producers jointly provide 40% of the equity and 40% of the debt for the Alaska segment of the line. Exxon's proposed investment levels (as publicly reported) are based on a cost estimate for the Alaska segment of $10 billion (presumably including both the pipeline and conditioning plant).

2. That in return for this investment, the Federal Government allow the treatment and conditioning costs, plus a rate of return to be included in the pipeline tariff, rather than absorbed by the oil companies at the wellhead.

FERC, of course, has been moving strongly in the direction of imposing treatment and conditioning costs upon the oil companies. It has been the FERC view that the approximately $2.00 per mcf price granted for North Slope natural gas by the Natural Gas Policy Act of 1978 is intended to include such costs. A final FERC rulemaking on this issue was scheduled to be complete this month. However, the Department of Energy has lead federal responsibility on technical issues relating to the treatment and conditioning of the natural gas, since FERC has defined it as essentially a production and gathering related activity. DOE is on the side of the oil companies in this respect, and Energy Secretary Charles Duncan has written a letter to FERC Chairman Charles Curtis requesting that the Commission re-examine its preliminary decision imposing treatment and conditioning costs upon the producers and allow such costs to be added on to the pipeline tariff.

If FERC is to reverse its decision with respect to treatment and conditioning costs at this late date, it seems likely that some relatively clear signal from the White House on the subject will be required. Also, the Exxon proposal seems designed to trigger precisely such White House action, since White House intervention will be required in any event to allow producer investment of the sort proposed by the company. It seems clear that Exxon has preempted the Federal Government on the question of producer financing by getting its demands on the table first. The result is that the White House and the Justice Department must now formulate some device whereby the language of the President's Decision forbidding oil company investment in the project can be sidestepped. Further, Exxon is placing the onus of a refusal to allow treatment and conditioning costs in the pipeline tariff on the Federal Government. They have turned what was previously considered a foregone conclusion into a negotiable point within their proposal, and it would seem that they are virtually forcing the Federal Government to either negotiate or to concede that private financing cannot work. At this juncture, it is difficult to predict whether FERC will stay with its original proposal to impose such costs upon the oil companies. However, one option is to grant some form of extraordinary relief as provided for in the Natural Gas Policy Act. It can, of course, be expected that there will be great opposition to any such proposal from consumer groups and FERC staff. Seen in the context of an upcoming election, it is difficult to predict what choice the Carter Administration might make between having producer financing available and enduring the wrath of consumer and liberal advocates.

The Exxon proposal would seem to be a useful blueprint for the type of policy that could be advantageous to the State. In short, Exxon's proposal seems to insure that if they finance, they will finance on their terms and that financing will be available for only a discrete portion of the project. If Alaska waits until all other participants have agreed to financing shares and proportions, the State may be pressured to join the cost overrun pool where obligations are theoretically open-ended and where management rights, equity ownership, and rates of return are relatively uncertain or absent. There is, of course, nothing magic about the Exxon proposal; it is something that the Alaska Legislature and the Administration could duplicate with relative ease.

The critical time for financing the project and with respect to Alaska participation continues to be the Spring of 1980. During this period, Northwest will be investigating financing sources with a view to obtaining FERC financing approval by the Summer of 1980. It also coincides with the period that the State Legislature is in session; consequently, great pressure upon the State can be expected from the period January - May 1980. Jack Rhett's rhetoric in our meeting of October 17 regarding his great concern over the State of Alaska's possible obstructionist role, his view that financial participation is required (not only technically but to provide an incentive for the State not to obstruct the project), and his flat-out statement that pressure might be brought upon the State if they do not finance, all tend to support the view that the first half of 1980 will be a critical period.

SUMMARY AND CONCLUSION

While the maneuvering on the pipeline issue remains at a high level, it remains very questionable whether this project will succeed during 1980. A possible alternative scenario could involve the period June 1980 - January 1981, during which it is very possible that Carter will be a "lame duck" President. To the extent that he uses this period to pay off old political friends, it could be a very rough period for the State of Alaska if the President attempts to move the project forward on the financing front by coercive measures against Alaska and the producers. This scenario is, of course, predicated upon the assumption that Alaska does not make progress with respect to financing during the Spring of 1980 (an arguable point) and that Northwest fails to achieve the requisite levels

of financing by the Summer of 1980 (a much less arguable point). On balance, however, it still seems most likely that renewed activity and a possible reformulation of the project will occur after the 1980 elections.

JOSEPH M. CHOMSKI, ESQ.

RICHARD G. HAGGART
Energy Consultant

JMC/RGH:brk

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES
REP. BILL MILES, CO-CHAIRMAN
REP. C.V. CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

November 20, 1979

TO: Rep. Sam Cotten

FROM: Mary Halloran MH
Research Analyst

As per your request, this paper reviews the projected national net economic benefits from the gas pipeline project, comparing the expected federal benefits to the estimated state benefits.

Two reports have been published on this subject: a May, 1979 ICF report, commissioned by the Federal Energy Regulatory Commission; and short comments filed on June 22, 1979, by EXXON in response to the ICF report.

ICF REVIEW

The ICF concluded that the National Net Economic Benefit (NNEB) would be $14.9 billion, distributed as follows:

Consumers (fuel cost savings)	$2.7 billion	(18%)
Producers (extra profits)	3.7	(25%)
Alaska (taxes and royalties)	4.7	(32%)
Federal Government (taxes)	3.5	(23%)
Pipelines (tax credit)	0.2	(2%)
	$14.9 billion	

The ICF conclusions are based on the following assumptions: the figures are in mid-1979 dollars; field life is 25 years; 6% discount rate applies; conditioning costs are paid by the producers.

If the discount rate used is changed from 6% to 10%, then the benefits would decrease as follows:

Consumers	$0.6 billion (mid-79 dollars)
Producers	2.2
Alaska	2.9
Federal Government	2.2
Pipelines	0.3
	$ 8.1 billion

AGO 532946

Enclosed is a summary page from the ICF report giving various NNEB scenarios under both 6% and 10% discount rates.

EXXON COMMENTS

The basic thrust of the ICF study was to "prove" that conditioning costs had to be shouldered by the gas producers in order for the consumers to receive any benefits from gas pipeline construction. EXXON responded to the ICF study with comments compiled by Foster Associates. They examined the net economic benefits with purchasers, not producers, bearing conditioning costs. The assumptions which differed in the EXXON-Foster work were the following: Alaska gas replaces distillate fuel oil, not residual fuel oil, and must be valued accordingly; thus, the cost of distillate fuel oil and real world escalation trends have to be used to draw comparisons; and purchasers must bear some, if not all, the conditioning costs.

The Foster work concluded that the net national economic benefit is much higher than that projected in the ICF study -- $27.2 billion, in fact. The distribution of that benefit would be as follows:

Consumers	$10.6
Producers	5.6
Alaska	5.2
Federal Government	5.4
Pipeline	.4

Under the EXXON scenario, the federal government benefits more than the State of Alaska from the gas pipeline project.

Neither the EXXON comments nor the ICF report were meant to be definitive; in fact, both are written largely to back specific stances on who should bear the conditioning costs. Until the question of conditioning costs responsibility is resolved, it will be difficult to determine which, the federal or the state government, will receive the larger share of tax returns from the project. In addition, the state's share will also depend on the final resolution of Amerada Hess v. State. If the producers are responsible for the conditioning costs and if they are allowed to subtract those costs from the wellhead value before calculating state severance taxes, then the monies the state receives could be significantly less from those otherwise projected.

In any case, it is not at all clear that the State's benefits will be significantly greater than the federal government's benefits from the project.

cc: Members of the Joint Gas Pipeline Committee

TABLE V-1

DISTRIBUTION OF NNEB FOR SELECTED SCENARIOS
(mid-1979 dollars)

Scenario	Net Benefits					Total NNEB
	Domestic Producer	Alaska	Federal Gov't.	Consumer	Pipeline Owners	
6 Percent Discount Rate						
Base Case	3.7	4.7	3.5	2.7	0.2	14.9
High Cost	3.7	4.7	3.5	-1.9	0.4	10.4
Base Costs, Medium Oil Price Escalation	3.7	4.7	3.5	10.1	0.2	22.3
Base Costs, Residual Oil Value, Low Escalation	3.7	4.7	3.5	-0.4	0.2	11.8
Base Costs, 3.2 Bcf/d Flow	5.2	6.4	5.1	5.4	0.2	22.3
Base Case With Gas Conditioning Charges	5.6	5.2	5.4	-1.7	0.4	14.8
10 Percent Discount Rate						
Base Case	2.2	2.9	2.2	0.6	0.3	8.1
High Cost	2.2	2.9	2.2	-2.5	0.4	5.2
Base Costs, Medium Oil Price Escalation	2.2	2.9	2.2	4.6	0.3	12.2
Base Costs, Residual Oil Value, Low Escalation	2.2	2.9	2.2	-1.3	0.3	6.3
Base Costs, 3.2 Bcf/d Flow	3.1	3.9	3.1	2.0	0.3	12.5
Base Case With Gas Conditioning Charges	3.4	3.1	3.3	-2.2	0.4	8.0

ICF INCORPORATI

AGO 532949

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES
REP. BILL MILES, CO-CHAIRMAN
REP. C.V. CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACHMAN

727 N ST., SUITE 2
ANCHORAGE, ALASKA 99501
(907) 276-4340

November 26, 1979

TO: Rep. Sam Cotten
FROM: Mary Halloran, MH Research Analyst

As per your request, this paper reviews the provisions for protecting the Northwest Alaska gas pipeline from unexpected and discriminatory taxation by Canadian provincial and federal governments. In brief, this issue was raised during the early pipeline proceedings, and the two governments, U.S. and Canadian, acted to prevent the possibility of discriminatory taxation.

First, provisions were made to ensure fair Canadian taxation in the Transit Pipeline Treaty which was ratified by the U.S. Senate. Second, these provisions were reiterated in the U.S.-Canadian Agreement on Principles which became part of the September, 1977, President's Decision, also later ratified by the U.S. Congress. Third, the Canadian Federal Government also obtained public endorsements of the provisions from the three provinces of British Columbia, Alberta, and Saskatchewan. These statements are annexed to the U.S.-Canadian Agreement. Finally, the Canadian House of Commons passed C-25, the Northern Pipeline Act, which includes both the U.S.-Canadian Agreement and the provinces' public endorsements of the taxing provisions of the Pipeline Treaty. Thus, the Canadian taxing procedures have been established through Treaty, International Agreement, and specific legislation.

A special provision was negotiated regarding ad valorum tax in the Yukon Territory, as no similar pipelines exist there. The Yukon Territory taxing structure is similar to Alaska's and will change only if the State of Alaska changes its property tax structure.

cc: Members of the Joint Gas Pipeline Committee

AGO 532950

SCOMM

#14:4

Joint Gas Pipeline Committee
Alaska State Legislature

need to keep?

SEN. MIKE COLLETTA, CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES
REP. BILL MILES, CO-CHAIRMAN
REP. CHAT CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR

EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACKMAN

POUCH V
JUNEAU, ALASKA 99811
(907) 465-3779

March 18, 1980

COMMITTEE REPORT

At its March 12, 1980, meeting, the Joint Gas Pipeline Committee heard a presentation by Earth Resources Company of Alaska (ERCA). ERCA proposes the State establish a tax exempt bonding authority for Prudhoe Bay gas liquids. According to ERCA representatives, the state authority would provide tax exempt financing, lowered cost of gas to the transportation system, and natural gas liquids for instate use. The proposal included draft legislation for the authority.

The Committee agreed to have the draft legislation prepared for introduction to the Legislature.

In further action, the Committee discussed a proposed budget for studies and continued activities by the Joint Committee. The Committee agreed to request a budget appropriation of $950,000 which would cover a financial consultant; engineering/design work on the gas conditioning plant and its location; liquids line study; economic feasibility of petrochemical industry study; options/uses and marketability of royalty gas study; study of federal control, pricing and tariffs and their impact on Alaska gas and gas liquids use; and staff for the Joint Gas Pipeline Committee and Governors-Mayors Task Force, travel and contingency.

AGO 532951

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES
REP. BILL MILES, CO-CHAIRMAN
REP. CHAT CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACKMAN

POUCH V
JUNEAU, ALASKA 99811
(907) 465-3779

March 31, 1980

The Joint Gas Pipeline Committee is holding an oversight hearing on the status of the contract between the State of Alaska and Alaska Petrochemical Company. The hearing will begin at 2:00 p.m., April 14, in Room 522 (Senate Finance), Capitol Building, Juneau.

AGO 532952

4/1/80

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA — CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES

REP. BILL MILES — CO-CHAIRMAN
REP. CHAT CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR

EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACKMAN

POUCH V
JUNEAU, ALASKA 99811
(907) 465-3779

April 10, 1980

M E E T I N G N O T I C E

The Joint Gas Pipeline Committee oversight hearing on the contract between the State of Alaska and the Alaska Petrochemical Company has been rescheduled for 2 p.m., Monday, April 28. The meeting will be held in Senate Finance, Room 522, Capitol Building, Juneau.

AGO 532953
4/14/80

scomm

#14:5

PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

APPENDIX D

Public Law 94-586
94th Congress

An Act

To expedite a decision on the delivery of Alaska natural gas to United States markets, and for other purposes.

Oct. 22, 1976
[S. 3521]

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

Alaska Natural Gas Transportation Act of 1976.

SHORT TITLE

SECTION 1. This Act may be cited as the "Alaska Natural Gas Transportation Act of 1976". 15 USC 719 note.

CONGRESSIONAL FINDINGS

SEC. 2. The Congress finds and declares that— 15 USC 719.

(1) a natural gas supply shortage exists in the contiguous States of the United States;

(2) large reserves of natural gas in the State of Alaska could help significantly to alleviate this supply shortage;

(3) the expeditious construction of a viable natural gas transportation system for delivery of Alaska natural gas to United States markets is in the national interest; and

(4) the determinations whether to authorize a transportation system for delivery of Alaska natural gas to the contiguous States and, if so, which system to select, involve questions of the utmost importance respecting national energy policy, international relations, national security, and economic and environmental impact, and therefore should appropriately be addressed by the Congress and the President in addition to those Federal officers and agencies assigned functions under law pertaining to the selection, construction, and initial operation of such a system.

STATEMENT OF PURPOSE

SEC. 3. The purpose of this Act is to provide the means for making a sound decision as to the selection of a transportation system for delivery of Alaska natural gas to the contiguous States for construction and initial operation by providing for the participation of the President and the Congress in the selection process, and, if such a system is approved under this Act, to expedite its construction and initial operation by (1) limiting the jurisdiction of the courts to review the actions of Federal officers or agencies taken pursuant to the direction and authority of this Act, and (2) permitting the limitation of administrative procedures and effecting the limitation of judicial procedures related to such actions. To accomplish this purpose it is the intent of the Congress to exercise its constitutional powers to the fullest extent in the authorizations and directions herein made, and particularly with respect to the limitation of judicial review of actions of Federal officers or agencies taken pursuant thereto. 15 USC 719a.

89-139 (497) O - 76

AGO 532954 +F

DEFINITIONS

15 USC 719b.

SEC. 4. As used in this Act:

(1) the term "Alaska natural gas" means natural gas derived from the area of the State of Alaska generally known as the North Slope of Alaska, including the Continental Shelf thereof;

(2) the term "Commission" means the Federal Power Commission;

(3) the term "Secretary" means the Secretary of the Interior;

(4) the term "provision of law" means any provision of a Federal statute or rule, regulation, or order issued thereunder; and

(5) the term "approved transportation system" means the system for the transportation of Alaska natural gas designated by the President pursuant to section 7(a) or 8(b) and approved by joint resolution of the Congress pursuant to section 8.

FEDERAL POWER COMMISSION REVIEWS AND REPORTS

Proceedings, suspension. 15 USC 719c. 15 USC 717w.

SEC. 5. (a)(1) Notwithstanding any provision of the Natural Gas Act or any other provision of law, the Commission shall suspend all proceedings pending before the Commission on the date of enactment of this Act relating to a system for the transportation of Alaska natural gas as soon as the Commission determines to be practicable after such date, and the Commission may refuse to act on any application, amendment thereto, or other requests for action under the Natural Gas Act relating to a system for the transportation of Alaska natural gas until such time as (A) a decision of the President designating such a system for approval takes effect pursuant to section 8, (B) no such decision takes effect pursuant to section 8, or (C) the President decides not to designate such a system for approval under section 8 and so advises the Congress pursuant to section 7.

(2) In the event a decision of the President designating such a system takes effect pursuant to this Act, the Commission shall forthwith vacate proceedings suspended under paragraph (1) and, pursuant to section 9 and in accordance with the President's decision, issue a certificate of public convenience and necessity respecting such system.

(3) In the event such a decision of the President does not take effect pursuant to this Act or the President decides not to designate such a system and so advises the Congress pursuant to section 7, the suspension provided for in paragraph (1) of this subsection shall be removed.

Recommendation, submittal to President.

(b)(1) The Commission shall review all applications for the issuance of a certificate of public convenience and necessity relating to the transportation of Alaska natural gas pending on the date of enactment of this Act, and any amendments thereto which are timely made, and after consideration of any alternative transportation system which the Commission determines to be reasonable, submit to the President not later than May 1, 1977, a recommendation concerning the selection of such a transportation system. Such recommendation may be in the form of a proposed certificate of public convenience and necessity, or in such other form as the Commission determines to be appropriate, or may recommend that no decision respecting the selection of such a transportation system be made at this time or pursuant to this Act. Any recommendation that the President approve a particular transportation system shall (A) include a description of the nature and route of the system, (B) designate

AGO 532955

APPENDIX C

SUMMARY OF TECHNICAL REPORT ON PRODUCERS' PROPOSED PLAN OF OPERATION OF THE PRUDHOE BAY FIELD

On August 18, 1976, a draft of the proposed Prudhoe Bay Unit Agreement was presented by the producers to the Alaska Department of Natural Resources. The draft included a summary of the producers' recommended plan of operations for the Prudhoe Bay Field. Subsequently, the producers prepared and submitted to the Alaskan authorities a technical report on the recommended operating plan. The report (Exhibit ALA-33) sets forth the results of the comprehensive technical studies conducted independently over the past several years by the major producers to develop long range operating plans for the Field. The following is a summary of that report.

According to the report, oil production is planned to commence in mid-1977 at a rate of 600,000 B/D, increasing to about 1,200,000 B/D by the end of 1977. Completion in 1978 or 1979 of field facilities necessary for the purpose will permit a further planned production increase to about 1,500,000 B/D when pipeline capacity is available. Such rate of oil production can be maintained for about 8 years by additional development drilling.

Until a gas pipeline and gas conditioning plant are approved and constructed, currently estimated to be 4½ to 5 years after the start of oil production, produced gas in excess of fuel requirements (1.8 to 2.0 Bcfd) will be injected into the gas cap without adversely affecting ultimate oil recovery. The gas conditioning plant will be needed to bring the gas to pipeline quality including CO_2 removal, extraction of gas liquids for hydrocarbon dew point control, dehydration, and compression and cooling to pipeline pressure and temperature. Preliminary estimates made several years ago indicate that the plant will require 4 to 6 years to design, fabricate and construct, and will cost about $1 billion (197[illegible] costs).

Once the necessary pipeline and conditioning plant are in place, gas pipeline deliveries of at least 2.0 Bcf/D will commence. Delivery at this level will require gas production of 2.7 to 2.8 Bcf/D to allow for fuel requirements, shrinkage and CO_2 removal. The 2.0 Bcf/D planned rate is a conservative volume which can clearly be supported by the reservoir, and initial gas pipeline deliveries of up to 2.5 Bcf/D may be justified, without affecting ultimate oil recovery.

Planned pipeline deliveries will substantially increase domestic energy supplies. For instance, through year 2,000, pipeline deliveries of 2.0 Bcf/D, beginning 5 years after the start of oil production, add the energy equivalent of 2 billion barrels of oil to the nation's energy supply. In addition, such gas deliveries reduce fuel consumption, eliminate unnecessary costs for compression, injection, and "double production" of gas, and provide a measure of correlative rights protection for the Oil Rim and Gas Cap participating area owners.

In the Main Area Sadlerochit reservoir, the natural recovery mechanism of the field will permit oil recovery predicted in the range of from 32% to 35% of the original oil in place. The current operating plan calls for the injection of produced water into the Sadlerochit when volumes become significant, increasing recovery to 33% to 36%. Studies indicate further potential for increasing ultimate oil recovery to a level of 39% to 40% of original oil in place by implementing a properly designed source water injection program within about 5 to 9 years after the start of oil production. Two or more years of production performance history and testing data will be necessary to confirm the additional recovery potential before the final decision is made to commit approximately $1 billion for source water injection facilities. It is estimated that oil recovery will be achieved over a period of 25 to 30 years. Ultimate gas recovery, expected to be in the range of 75% to 80% of total gas-in-place, will be recovered over a period of about 35 years.

It is expected that significant volumes of gas cap gas will be produced through oil wells. If this gas is not delivered to a pipeline, it will be necessary to reinject an estimated 15 to 20 Tcf of gas into the gas cap. Although the return of such gas is not detrimental to reservoir performance, compression and injection of this volume would require about 600 to 800 Bcf of fuel gas, or the energy equivalent of more than 100 million barrels of oil. Moreover, the extraction of liquids required to condition the gas for pipeline delivery will provide for an additional 10 million barrels per year of gas liquids. All liquids extracted will be used without waste; either to displace fuel gas or be transported through the oil pipeline with the crude oil and condensate. 1/

1/ A gas cap gas condensate yield of about 35 barrels per MMcf of separator outlet gas is expected initially from the separator facilities.

XVII

SUMMARY

The extensive discussions above give some of the flavor of the public debate now underway as to which pipeline applicant should be certificated and what degree of consumer or taxpayer involvement is warranted. The full measure of interest and controversy also was displayed in the plethora of Wrap-up Briefs and Position Briefs filed by all the applicants (including affiliates), intervening states, natural gas transmission companies, distribution companies, Conservation Intervenors and Staff.

As has been stated supra, Staff, charged directly with representing the public interest, supports the Arctic Gas project (without the western leg) as vastly superior. The Conservation Intervenors support Alcan, on environmental grounds. Of those states which support a particular project in their Final Briefs, the majority choose Arctic Gas. New York, Wisconsin and California voice support for the Arctic Gas system. 1/ It is significant, in fact, that the most populous states in the east and west, and one of the largest in the midwest all see their interests best served by the Arctic Gas project, if any Alaskan gas delivery system is built. California's preference is predicated in part not on the economics of these proposals, which it finds marginal, but on the ability of Arctic Gas to move the additional supplies it expects to come from the far north. Alaska is the only state which supports El Paso, based on the perceived environmental, socio-economic and reliability benefits. Interestingly, Washington and Oregon do not state a preference for any project, but, like California, state their support for Arctic Gas with a western leg (if Arctic Gas is certificated). Utah supports an overland route with a western leg. Arizona, while not preferring any system, wants assurances that it will have direct access to, and an equitable share of, Alaskan gas. This argument seeking to allocate gas supplies is premature in that no producer sales contracts have been entered.

Of those gas transmission and distribution companies which support a particular project, the majority choose Arctic Gas. Algonquin Gas Transmission Company (New England), Michigan Consolidated Gas Company (Michigan), Wisconsin Gas Company (Wisconsin) and

---

1/ The State of Wisconsin petitioned to intervene in January, 1977, and the Commission approved intervention by order dated January 25, 1977.

the New York Gas Group (New York) favor Arctic Gas. Intermountain Gas Company (Idaho) supports Alcan, on the basis of environment and reliability. Tennessee Gas Pipeline Company and Southern Natural Gas Co. prefer El Paso, but their views can be given little weight. As is conceded in the briefs, these companies have signed agreements with Alaska to purchase royalty gas, and thus were contractually bound by Alaska to support El Paso. Cascade Natural Gas Corporation (Washington and Oregon) and Washington Water Power Company (Washington) only voice their support for a western leg and, of course, all of the many major transmission and distribution companies sponsoring Arctic Gas support their project.

In a sense, there is a consensus on the part of the Commission Staff, the most popular consuming states taking an active interest, and an array of pipelines and distributors serving huge sections of the country that if any pipeline applicant must be chosen now, their best interests would be served by choosing Arctic Gas. The evidence in this record clearly supports that conclusion. There is no need to summarize here the findings made in the individual sections above. The Arctic Gas application is superior in almost every significant aspect when compared to El Paso. Certification of its proposal, subject to appropriate conditions, will bring more energy to market cheaper and more reliably than El Paso and will do so in an environmentally acceptable manner. It is found that Arctic Gas' prime route should be certificated, including both western and eastern legs.

El Paso, too, has a viable plan which technically can be built in an environmentally sound manner and which can deliver natural gas to all U.S. markets. While its certification is less desirable because of the reasons discussed above, nonetheless, it could be certificated if it were not for the clearly superior Arctic Gas application. Thus, if Arctic Gas is unable to accept a certificate, this record supports findings that El Paso's proposal, as required to be modified by the findings above, would also meet the present and future public convenience and necessity.

No finding from this record supports even the possibility that a grant of authority to Alcan can be made. No grant could include Westcoast, but its sponsors state that exclusion of Westcoast would render Alcan's financial plan inoperative. The allocation procedures supported in the record by AGTL are now inoperative according to AGTL, and this means no meaningful costing of facilities can be made from this record. Furthermore, Alcan's present design is clearly neither efficient nor economic since the pipeline is undersized. The suggested three years construction schedule to be completed by 1981, which Alcan argues is one of its

prime strengths, cannot occur. Moreover, its arguments as to how it can be financed in separate time frames from Maple Leaf, also critical to its proposal, requires intricate timing that is totally unsupported by hard evidence. As presently proposed, even with Alcan's willingness to build anything anyone wants (as long as it does not oust Westcoast and AGTL from their Maple Leaf project), there is not enough left of its original proposal to serve as a basis for granting its application.

Nahum Litt

Nahum Litt
Presiding Administrative Law Judge

XVI

PROPOSED LEGISLATION

A. Section 13 of the Alaska Natural Gas Act of 1976

The State of Alaska has entered into contracts for the interstate sale of its royalty gas which include provisions permitting the State to subsequently withdraw the gas from the interstate market for use within the State. These withdrawal provisions are sanctioned by Section 13(b) of the Alaska Natural Gas Act of 1976.

However, as discussed in the Jurisdiction and Financing sections of this Initial Decision, substantial difficulties arise from the State's asserted right to commit its gas to interstate use with one hand and take it back with the other. The mere prospect of withdrawal imperils the financeability of an Alaskan gas project; actual withdrawal would idle downstream facilities and in turn produce adverse cost impacts.

Moreover, when the Section 13(b) withdrawal provision is coupled with the Act's "equal access" provision, 1/ it becomes readily apparent that the statute in its present form could operate to confer a substantial indirect subsidy to the State. Assuming that the project could be financed and completed, that Alaska's interstate customers (El Paso Natural, Tenneco Alaskan, and Southern) participated in the equity financing with consumer guarantees, and that Alaska thereafter found an intrastate use for its royalty gas, the consumers of the three customer companies would have risked their dollars to help finance the project, only to see consumers in Alaska reap the reward.

For the reasons stated herein, the Presiding Judge respectfully suggests that the Commission, in its recommendation to the President, give consideration to the desirability of amending the Alaska Natural Gas Act of 1976 to delete therefrom Sections 13(a) and 13(b). Absent deletions of these two provisions, direct and total U.S. government guarantees would appear to be the only feasible method of financing.

1/ Section 13(a) of the 1976 Alaska Natural Gas Act would deny the Commission the power to limit access to the transportation system to shippers participating fairly in its equity financing. It is questionable whether the proposal to finance an Alaskan project with consumer guarantees is possible in the face of this statutory provision.

B. Other

Unlike the preceding extended discussion respecting Section 13 of the Alaska Natural Gas Transportation Act of 1976, the need for the following legislative recommendations has been adequately addressed in the Financing and Potpourri sections, supra:

1. LNG Ships

To insure effective regulatory control of rates and operations of the El Paso tanker fleet, explicit statutory jurisdiction should be conferred on the Commission.

2. Tracking

Full and timely recovery from ultimate consumers of all appropriate costs in connection with an Alaskan transportation project, during both the construction and operations periods, requires implementation by Federal legislation. The Commission should not have the power to suspend such flow through of costs, but the right to review all such costs at all times, with the power to order refunds where appropriate, should be preserved.

3. Federal Financial Participation

The Treasury Department should be granted statutory authority necessary and appropriate to accomplish whatever Federal participation in the Alaska gas project financing is ultimately determined to be required in the public interest.

Army personnel.

The crew was identified as: Capt. Donald W. Deeter, 29, pilot, of Fillmore, Calif.; CWO Ralph G. Battle, 38, copilot, Miami, and Spec. 4 Paul E. Jones, crew chief, St. Cloud, Fla.

Passengers, all stationed at Ft. Richardson, were identified as: Lt. Col. William I. Barrett Jr., Beckley, W. Va., commander of the 1st Battalion, 43rd Air Defense Artillery; Lt. Col. John S. Edge, 42, assistant post commander, Americus, Ga.; Maj. James W. Nelson, 38, operations officer of the 1st Battalion, Greenville, Ala. and Major Melvin J. Swiney, Tacoma, Wash.

confirmed that the strike had ended, but declined to discuss details of the settlement.

The strike, which began Feb. 2, cost Sea-Land an estimated $1.38 million. While some company services were disrupted, supervisory personnel performed many delivery functions. At one point Teamster pickets followed Sea-Land trucks around to picket unloading operations.

Inside today

Alaska Living	6,7	Obituaries	17
Ann Landers	7	Opinion	4
Comics	13	Sports	9-11
Crossword	15	Television	12
Jack Anderson	17	Want Ads	14-17
Money	5	Weather	17

measure authored by Sen. Chancy Croft, D-Anchorage, establishing another commission to conduct more studies, this round to be completed by January of 1978.

Lethin's plan was met with solid support by Matanuska Valley residents who testified in Palmer Friday night. But response from the 26 Anchorage residents who testified Saturday and Sunday was mixed.

Hearings will move to Fairbanks next weekend.

AS EXPECTED, however, testimony took a 180-degree turn from that heard in Juneau last week, where most of those who testified sidestepped the bills under consideration and relied upon emotional appeals to keep the capital in Juneau.

Among those testifying Sunday was Anchorage attorney Gale McCarrey, who suggested that capital design should be submitted to international bid.

"I'm sure lots of architects would like their names ascribed to the new Alaska capital," McCarrey testified.

McCARREY ALSO said he didn't think the new capital would cost "too much money."

"IT PROBABLY WILL BE more intriguing to hear the comments in Fairbanks," said Bradley, who will chair the hearings there.

Bradley said he was disappointed there wasn't a "higher incidence of man-of-the-street comment in Anchorage."

"I would have liked to have seen 200 people and only 20 architects or planners," he said.

MEANWHILE, A study was released estimating that it would cost about $214,000 a month to set up temporary government offices near Willow. The study, prepared for Lethin, did not take into consideration the cost of housing.

Several Anchorage engineering, architectural and modular construction firms were involved in the preparation of the study. It was based upon creating office space for the governor, lieutenant governor, and the legislature.

A total of 80,000 square feet of office space would be provided.

State at odds with gas plans

By G. MICHAEL HARMON
Associated Press Writer

JUNEAU — Oil industry proposals for the earliest possible delivery of massive amounts of Prudhoe Bay natural gas to the lower 48 states have been quietly but firmly squashed by the State of Alaska.

The dispute, which may place Alaska interests in direct conflict with national energy demands, centers on major differences between state and oil industry officials over how best to manage the North Slope reservoir's 19.5 billion barrels of oil and 26.5 trillion cubic feet of natural gas.

Oil industry officials say their plan "provides for expeditious and economic development of the total energy resources at Prudhoe Bay consistent with good oil and gas conservation practices."

In challenging the proposal, however, state officials say the operators' plan may be motivated more by a "disincentive to produce oil because they have a surplus on the West Coast and an incentive to produce gas because it's very dear right now."

At the center of the intense but unpublicized debate are two conflicting documents obtained by The Associated Press—the industry's "operating plan" for exploiting Prudhoe Bay reserves and a sophisticated state-financed computer "prediction of reservoir fluid recovery" from the field.

In its proposed operating plan, the industry has asked the state to guarantee the delivery of at least two billion cubic feet a day of gas by mid-1982, about five years after this summer's planned start-up of the trans-Alaska oil pipeline and the earliest possible date projected by the oilmen for completion of a natural gas pipeline and conditioning plant.

But state officials, who have been involved in confidential negotiations with the Prudhoe Bay producers over the operating plan for more than three months, have steadfastly rejected the industry management scheme on the premise that it violates Alaska's tough conservation statute for the maximum production of both oil and gas.

In it's computer projection, the state contends that the delivery of two billion cubic feet a day of natural gas under the industry plan could cause the loss of as much as 1.6 billion barrels of oil, a significant figure in light of the acknowledgement by both sides that under the best of circumstances ultimate oil recovery from the field will total a maximum of only 40 per cent of the oil in place.

In an effort at compromise, the state says it could allow the gas delivery rate proposed by the oilmen if they will commit themselves to a massive water injection plan at the North Slope field.

All-Alaska gas line risks

Page 2

While acknowledging that the injection of water from the Arctic Ocean could help offset the loss of field pressure from early, large-volume production of gas, industry officials say they cannot and will not commit themselves to the $1 billion-plus cost of a source water injection project without several years of field history.

In contrast, the industry plan says field history is not needed for the state to guarantee early, massive gas offtake rates, an inconsistency noted by the state in rejecting the operating proposal.

The operating plan submitted by majority owners of North Slope reserves, British Petroleum, Atlantic Richfield, Exxon and Sohio, repeatedly emphasizes that "state approval of the gas offtake plan is needed now to insure that FPC (Federal Power Commision) certification, final design, financing and construction of the pipeline can proceed on schedule."

It defends the proposed offtake rates on the grounds that they would "immediately increase current epergy to the consumers and current income to the owners."

State Natural Resources Commissioner Guy Martin says that considering the massive investment the oil industry has in Prudhoe Bay, including $7 billion in trans-Alaska oil pipeline costs alone, he was not surprised that the industry has balked at financing a massive water injection project or may be willing to sacrifice long term oil production for early gas profits.

"They would love it if the state would give them a guarantee, but we won't," Martin says. "It may be they have a disincentive to produce oil because they have a surplus on the West Coast and an incentive to produce gas because it's very dear right now.

"But I think they know that in order to get the levels of gas production they are talking about under our conservaton statute, it is going to be necessary for them to have to have a water injection plan."

Without a commitment for massive water injection, Martin says the state probably will not set an initial gas offtake rate of more than about 1.6 billion cubic feet a day, a figure that is below the threshhold of feasibility for two of three competing gas pipeline projects.

And even with water injection, Martin says the state won't give the industry any absolute guarantees in advance for the estimated 20-year life of the field.

AGO 532963

PLEASE NOTE: THE PRECEDING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

TESTIMONY FOR ROYALTY GAS SALES CONTRACTS

Jefferson B. Barry, Anchorage, Alaska,
representing Teamsters 959
February 19, 1977

Senator Kay Poland, Chairman, Resource Committee,

Senator John Sackett, Chairman, Finance Committee:

The instant issues before the legislature are the royalty surplus gas sales contracts, but they are admittedly only a stimulus for the larger issue of an all-Alaska gas line with access of our own gas for our own uses. Since this is the only legislative forum available our testimony will include the entire matter.

On the instant issues of the royalty surplus gas sales contracts we support the legislative concurrence, provided certain modifications are incorporated:

1. (a) In the Tenneco Alaska, Inc. contract substitute the words of 40% instead of 50%.

(b) In the El Paso Natural Gas Company and the Southern Natural Gas Company contracts, substitute the words of 20% instead of 25% for both of such contracts.

It is vital and necessary that Alaska demonstrate there is an immediate intrastate use for domestic, residential, and power use of a portion of our gas. Certainly the ability to ship LNG to communities within our state must be present and the current application requests of Fairbanks honored.

I point out the most dynamic and stable growth area in the state has been Cook Inlet. The great denominator comes with natural gas for power, industry, and domestic, residential use. The rest of our state is surely entitled to those same opportunities. With an assured supply other communities can plan to realize those advantages.

As for Anchorage, Thomas Stahr, Manager of M.L.& P., testified before the Joint Committee that gas committed to the Anchorage area will run out in the mid-1980's and the

state must assure that Prudhoe Bay royalty gas is available for in-state use.

It is equally important the Federal Power Commission have this contract understanding. Judge Litt, on page 20 of his initial decision, addresses the question of the state contracts and he states, "...given the contract terms, such support is entitled to little weight. The purpose of such reservation is to insure that the amount of royalty gas exported from the State is 'surplus'--whatever that means--to the State's intrastate domestic and industrial needs--whatever that means." And, in a footnote, "Upon reflection, Alaska decided not to seek a reopening of the record for the appearance of a state witness with respect to the contracts."

Upon the evidence presented to Judge Litt he had no knowledge that the vast majority of Alaskans have never had the energy benefits of natural gas or that the small area that has may soon be blacked out.

You should modify the contract to show that Alaska reserves the use immediately for 2.5% of its own gas within the state. Only in that fashion can the FPC make an evidentiary judgment of the need and meanings of our contracts.

2. The section of the contract 11.4 should be modified to clearly illustrate the State's interest is solely the El Paso Company docket #CP75-96 and the conditions apply to none other than the El Paso proposal.

There are ample time limits incorporated in Public Law 94-586 The bell tolls for thee and me as follows:.

Sec. 5(b). The Federal Power Commission shall submit to the President not later than May 1, 1977, a recommendation--

Sec. 7(a) As soon as practicable after July 1, 1977, but not later than September 1, 1977, the President shall issue a decision--

Sec. 7(2) The President, for a period of up to 90 additional calendar days after September 1, 1977 may delay

the issuance of his decision and transmittal thereof--"

Sec.8(a) Any decision--shall take effect upon enactment of a joint resolution within the first period of 60 calendar days of continuous session of Congress--"

Thus, it is clear the governor of Alaska has all of the necessary time by Federal statute to obtain the statutory requirements of approval by Legislative concurrence to "switch" any route assignment other than El Paso.

We believe the inclusion of 11.4 in the contract is destructive to the proclaimed intent of total support for the El Paso pipeline and a studied attempt to thwart legislative concurrence.

It is interesting to note the Federal Law 94-586 authorizing the Presidential decision requires Congressional affirmation. So do Alaska's laws. But this contract would abrogate that decision process by granting the Governor the power to "switch" without Legislative concurrence.

It would be a bad precedent to establish. We are totally opposed to 11.4 and suggest it be eliminated from the contract.

This concludes our testimony upon the minimal modifications required to approve the royalty gas sale contracts.

We now address the larger, most salient issue of the all-Alaska Gas Line and approval thereof according to the Alaska Natural Gas Transportation Act of 1976.

Congress has mandated certain actions, and many without judicial review. These are going to occur and the only course we may pursue is to adapt to them.

ACT AND INTIAL DECISION

The best place to begin is with Public Law 94-586, the Alaska Natural Gas Transportation Act, pointing out several emphatic statements:

> Sec. 2.(3) "--delivery of Alaska natural gas to United States markets is in the national interest;-
>
> Sec. 3 "--To accomplish this purpose it is the intent of the Congress to exercise its constitutional powers to the fullest extent in the authorizations and directions herein made,--"
>
> Sec. 4(1) the term "Alaska natural gas" means natural gas derived from the area of the State of Alaska generally known as the North Slope of Alaska, including the Continental Shelf thereof;

That's the heart of the matter. Congress has enacted a law in the national interest and will exercise its constitutional power to the fullest extent, and Alaska natural gas means ALL OF THE GAS NORTH OF THE BROOKS RANGE OUT INTO THE CONTINENTAL SHELF.

The implications are horrendous. From the largest gas reserve on the North American continent, from its own land, Alaska may not get one cubic foot of its own gas from Prudhoe Bay, from undiscovered sources in the Beaufort-Chuckchi Seas, nor may gas discovered on Native Lands in that area be available for other Alaskans and communities.

If the Canadian Arctic route is approved the result is an expropriation of Alaska's property and energy. Most Alaskans want access to their gas, and certainly want the national interest of the lower 48 served with the vast amount of reserves on the North Slope.

Prior to the enactment of PL94-586 and concurrent since, the Federal Power Commission hearing process commenced on May 5, 1975, and essentially has continued almost uniterrupted since that time.

The record closed on November 12, 1976. It consists of 253 volumes of transcript, embracing almost 45,000 pages, about 1,000 exhibits (some, such as the environmental impact statements being almost 1,000 pages each), and innumerable items by reference.

Roughly, half the States, most of the U. S. natural gas pipelines, and a plethora of prospective purchasers and other interested parties intervened.

On February 1, 1977, the Federal Power Commission issued Order No. 558B:

> The parties that have participated as adversaries during the long course of hearings have had more than adequate opportunity to place on the record their positions regarding the completing projects and the "data, views and arguments" in support of their positions. The quality of information available to the Commission would not be enhanced through mere repetition of that discourse. Furthermore, an unqualified departure from the principles of the ex parte rule would create a potential for unequal access by the competing parties to the decision process without contributing reliability to the result. Therefore, the Commission or delegates should not communicate in relation to substantive matters with the applicants or affiliates thereof or parties, counsel, or witnesses (including Commission staff witnesses) that have advocated on the record the approval or rejection of any of the competing projects.

For more than 2 weeks we have been analyzing Judge Nahum Litt's 430 page Initial decision.

It provides a shocking indictment of the State Administration concept of the Federal Power Commission hearings and the consequences of the enactment of the Alaska Natural Gas Transportation Act. The Administration has been remiss and derelict in its obligations to Alaska's citizens.

The record is replete with the evidence that the State Administration had no clear purpose nor pursued a determinative goal compatible with extraordinary Federal legislation and regulations. It is no wonder that Judge Litt perceived the State so poorly, and I intend to place that performance in the record.

The State was dilatory and uncooperative.

AGO 532968

Page 12.

Upon the commencement of the hearings in May 1975, a running dialogue was instituted with the State of Alaska and producers seeking, inter alia, to ease them to a position where they might perceive that their best interests coincided with the national interest to have contracts for sale submitted at the earliest time during the pending hearings. This effort was singularly unsuccessful insofar as sales agreements were concerned, although some progress was made in at least getting the Producer to discuss these matters on the record. Only on the last day of hearing, November 12, 1976, did the State announce sales of its royalty gas to El Paso Natural Gas Company, Southern Natural Gas Company, and Tenneco Alaskan, Inc. But even these contracts for the royalty gas are not effective until ratification by the State legislature, which is not in session.

Page 13.

of course which has burdened this record. Thus, while stating their concern for the national interest and the requirements of this country for energy at an early date, their prime consideration for early sale turns on other more parochial interests. The only conclusion possible from their actions is that the national interest to ARCO, Exxon, Sohio, etc. lies somewhere below their own

Page 14.

economic interest, or at least, the national interest of the U.S. appears to them as negotiable in their bid to obtain certain concessions from the Commission or the Congress in return for their cooperation in bringing this gas to market. 1/ Admittedly, the uncertainty of regulation is not as bankable as the 3/4 billion dollars ARCO, for example, had negotiated as advance payments by prospective Alaskan gas purchasers before the Commission found such payments against the public interest. But it shows that the producers, like G.B. Shaw's dinnertime companion, have a price at which they would sell their "service," and all of their protestations to the contrary cannot hide that they are mainly dickering over price. The record, unfortunately, now stands with no firm commitment on the part of any producers to sell natural gas, or even that they will agree to sell it immediately upon tentative certification of a successful applicant.

The State of Alaska's role as a royalty owner, taxing agent, and conservator of its resources is also at issue. The State of Alaska embarked early on upon a course designed to maximize the economic benefits flowing to Alaska from its hydrocarbon resources. This laudable goal for Alaskans, unfortunately, is not always consistent with the general public interest of all of the people of the United States. It may portend, again unfortunately, a confrontation on the merits of an indirect transfer of payments from other parts of the country to Alaska through excessive payments for Alaskan hydrocarbons. These are not easy questions: the State's demands were not crudely put nor outrageous on their face. The difficulty is that they are also not always obvious, and it is not easy to gain a clear picture of the State's demands or whether those who deal with the State privately are in a position to bargain effectively for the public interest. Any Prudhoe Bay field operating plan must be sanctioned by the State, and the producers may, for example, agree to conditions in the field production arrangements which could be quite detrimental to long-term consistent sales of interstate gas.

In addition to the lack of sales agreements, there is still no approved production agreement for oil or gas from the Prudhoe Bay Field. A draft agreement was presented to the parties for the first time on August 18, 1976, some 7 or 8 months after it was first suggested it might be filed.

Page 32.

The producers state that once the necessary pipeline and conditioning plant are in place, gas deliveries of at least 2.0 Bcf/d will commence. No one at this time questions the producers' statement that there is a 4-6 year lead for constructing the gas conditioning plant. The volume itself is termed as conservative, and they state that initial gas deliveries of up to 2.5 Bcf/d may be justified without affecting ultimate oil recovery. Produced water will be reinjected into the field, and the producers cite studies

AGO 532969

indicating further potential for increasing oil recovery by implementing a source-water injection program. However, at least two years of testing are said to be necessary after the field goes into oil production before the final decision is made to construct source-water injection facilities. In approving the plan, an issue may exist between the producers and the State as to the need for, and timing of, source-water injection.

The vast weight of the evidence is that between 2.0 Bcf/d - 2.5 Bcf/d of gas will be available initially from the Prudhoe Bay Field.

What has occurred this past week? Commissioner Guy Martin received front page coverage by stating that "without a commitment for massive water injection the State probably will not set an initial gas offtake rate of more than 1.6BCFD, a figure that is below the threshold of feasibility for two of three competing gas pipeline projects."

Incidentally, one of those not feasible is El Paso.

It is simply incredible confusion. Early in the hearings the State exhibited the Van Poollen report which confirmed the 2 BCFD and even higher recovery rates by further water injection. No place in the record is there the hint of a 1.6 BCFD recovery rate. It is fully understood that for the yeras between oil production and gas line completion that the gas will be reinjected in the gas cap, approximately 4-5 years.

Now, at this late date, Commissioner Martin is compounding the confusion for those who must make timely decisions.

This threat, by unilateral decision, to restrict recovery rate below feasibility of El Paso and Arctic proposals cannot improve our "parochial image of self-interest."

It is one thing to argue with the producers and protect the conservation of our oil and gas. However, it is entirely a different matter when Alaska fails to enter into the records a clear position of policy whenever any relevant facts are known.

The acute shortage of natural gas in the lower 48, our possession of 10% of the nation's supply, should have

mandated the Administration to take a leadership role in the choice of the route selection.

But examine the record:

Page 254

(Alaska Initial Socio-Economic Brief, 12):

> The El Paso project would create far more employment within the State, would increase population along the southern coast of Alaska to the extent that that portion of the State at least would have a private economy of reasonable size, and would provide far greater State and municipal revenues in order that the governmental units can cope with the socio-economic costs that are certain to result from any of the projects. When the benefits of the El Paso project so far outweigh any of its costs, and when its net socio-economic benefits would so far exceed those of the Arctic Gas Projects the State cannot conceive of refusing to grant the El Paso project a preference on socio-economic grounds....

Page 264

D. Intrastate Use of Royalty Gas

Alaska argues that, in addition to favorable impacts on employment, population, gross state product and net government revenues, the El Paso project will allow and in fact encourage industrial development in central Alaska. The State, eager to shed its dependence on the lower 48 states and its unstable, boom-or-bust economy, envisions the development of mineral reduction, fertilizer, cement, and petrochemical industries that can use the royalty share of the Prudhoe gas. 1/ Langhorne Motley, Commissioner or Commerce and Economic Development for the State, testified to the importance of this development and the potential for enticing industry into the State once the gas pipeline is completed. However, no cost-benefit analysis was performed concerning the intrastate vs. interstate use of royalty gas. On the whole, moreover, he was unable to detail concrete examples of discussions with prospective industrial users, and the State's use of Alaskan gas remains speculative, at best. The fact is that Cook Inlet gas supplies did not spur any substantial development, although Alaska argues that development of Cook Inlet gas involves piecemeal discoveries at a time when there were sufficient supplies of low-cost gas in the lower 48 states.

Page 265

1/ Guy Martin, Commissioner of Natural Resources for Alaska, indicated that the State would also benefit from a gas liquids removal plant built in Alaska, if El Paso was certificated.

1/ Governor Hammond testified that an oil refinery is planned for the Fairbanks area. Thus, there will be energy supplies available to central Alaska, even absent a trans-Alaska pipeline (96/14,675). Moreover, it should be noted that the use of gas for residential purposes in a cold climate such as Alaska's might be economically impractical, given the necessarily high fixed costs involved and the poor load factor.

In sum, there are so many uncertainties involved in intrastate use of royalty gas that no findings that it will occur are warranted at this time.

This is an unbelievable record for Alaskans to accept. Why was no cost-benefit analysis made? Why were not communities consulted for the use of natural gas, LNG, or LPG? Why were not the requests for Fairbanks users not part of the record? (downtown Fairbanks has had piped propane for business uses for about 20 years). Why were there no concrete examples of prospective industrial users--when Dow Chemical, for one, had made a proposal to the previous administration; that Dupont, Celanese, Rexall, to name some prospects, have indicated interest?

There aren't so many petro-chemical companies that the State Administration would have been burdened to have sent letters of inquiry over possible interest.

The lack of such attention to Alaska's intra-state use is magnified by the sales contracts to be shared by Tenneco 50%, Southern 25%, and El Paso 25%. When the FPC staff and Judge Litt examined the evidence of the record they properly found no consumers nor identifiable prospective users.

Page 266

The major benefits the State derives from the El Paso proposal are the jobs and tax base of a multibillion dollar, 800-mile pipeline and LNG facilities, the liquid removal plant which would be built by the producers in Alaska (probably at Gravina Point), the additional industry which would settle in the State to utilize cheap energy, and the multiplier effect upon the State's economy by all of the above. But the result of giving disproportionate weight to these considerations and choosing an all-Alaskan route even if more expensive, rather than basing the decision on an analysis of costs and benefits which redound to all consumers, is no different than that already rejected by the Commission and the courts.

The Administration did not make a case for Alaska.

Next, let's look at the greedy image protrayed by the State's evidence:

page 357

One of the prime reasons for these high projected prices for delivered gas, of course, is evident from the makeup of the project. Rather than the usual business compromises arranged both to make a marketable product and to split the benefits among those who will gain the financial advantages from a successful venture, all of the prospective beneficiaries are looking for the top dollar. The producers and State of Alaska want a high wellhead gas price even though (1) their overall profit from their North Slope investment is already assured by the sale of the Prudhoe Bay oil under FEA regulations, (2) the product is at the end of an expensive transportation system, and (3) the market is no longer assured. Governor Jay S. Hammond of Alaska, for example, sought and will probably seek again Alaskan legislative approval to raise the severance tax on hydrocarbons from 4% to 10%. Access without equity contribution, 3/ withdrawal, underlifting and a host of other proposals put Alaska in the forefront of seeking special treatment at the consumer's expense. As discussed in the rate-of-return section, the pipeline shippers want consumer guarantees to repay their equity investment but still seek 15% to 17% after tax return in what could be a low-risk situation. The financial community in general also wants a high rate of return regardless of how the risk might be reduced by consumer or taxpayer guarantees. In the common vernacular, "everyone has his hand out."

According to the record it appears Alaska has both hands out --- high well-head prices, high taxes, and no risk.

It is also interesting to note then El Paso raises the specter of Canada or the provinces imposing heavy taxes but is the Governor of Alaska who is in the record for a 150% increase.

There is no evidence the State of Alaska, the beneficiary of billions by the marketing of Prudhoe gas, has offered any incentives or economic inducements toward the resolution of the route, the facilities, or field systems.

page 366

The field prices to be paid by shippers to producers for gas volumes delivered into the transportation system will reflect more than just the purchase of the commodity itself. Between the well-head and the delivery point, there must be constructed an extensive gas gathering system and conditioning plant at a total capital cost, excluding interest during construction, estimated by the producers to be $1.8 billion. This cost, the producers aver, must be borne by the shippers. It is readily apparent that these facilities will not "cost out" at the few cents per MMBtu familiar from past area and nationwide rate proceedings. Producers

have presented short-hand calculations, based upon the Arctic Gas project costs, suggesting that the unit cost of gathering and conditioning to be borne by the shippers will approximate one-half the unit cost of the transportation system (213/36,931 et seq.). 1/ One need not rely on these unsupported and untested calculations to realize that, given the magnitude of the capital investment, the unit cost will be high. All of these high transportation and field facilities costs are bad news for consumers--and for the producers and the State of Alaska.

page 362

Nor, according to Governor Jay S. Hammond of Alaska, has the State seriously considered offering any of the applicants financial assistance (96/14,688).

The State has gotten itself into a legal hassle, over jurisdiction of interstate sales and its proposed royalty sales.

How serious Judge Litt viewed the legal question is confirmed by his proposed legislation to delete Section 13(A) and (B) from the Act.

To begin with, respecting wellhead sales in Alaska, jurisdiction is unquestioned only as to interstate sales by the corporate producers. The State of Alaska resolutely denies federal jurisdiction over its interstate sales.

The State of Alaska's position, in the Presiding Judge's view, is contrary to the law and to effective or equitable regulatory control. The sole basis for its denial of jurisdiction is the claim that a State is not a "person" within the meaning of Section 2 of the Act. 1/ Thus, activities which, by their nature, Congress intended to place under regulation are said to be exempt when performed by a State. There is no such gap in the law, and one should not be created. The producing and energy-rich States of the nation, by virtue of their royalty interest where production is from state land and their increasing propensity to reserve the right to take that interest in kind, will have the ever-growing ability to dispose by sale of larger and larger volumes of gas and will expand such a gap to permit larger and larger volumes to escape regulatory control. In this proceeding alone, Alaska has recently entered into contracts to sell in interstate commerce up to 2.6 Tcf of its royalty gas.

Alaska's jurisdictional argument, moreover, is hardly compatible with the Act's purpose to afford consumers an effective bond of protection against excessive rates 1/ or the intention of Congress "to give the Commission jurisdiction over the rates of all wholesales of natural gas in interstate commerce ..." (emphasis added). 2/ Furthermore, Alaska's essential premise is undercut by the holding in F.P.C. v. Corporation Comm'n of Oklahoma, 362 F. Supp. 522; aff'd 415 U.S. 961 (1974), that a state agency is a "person" within the meaning of Section 2 of the Act and thus the U.S. District Courts have jurisdiction under Section 20(a) to enjoin its actions violative of the Act or

regulations thereunder. The question of jurisdiction over Alaska's proposed sales is not squarely at issue in this proceeding, and the parties have not provided legal argument on the question only because sales contracts were not filed earlier. The need for the Commission to give prompt attention to and definitively resolve the matter is apparent, since any attempt to finance these projects must be predicated on knowledge of the transactions that are jurisdictional. 3/

XVI

PROPOSED LEGISLATION

A. Section 13 of the Alaska Natural Gas Act of 1976

The State of Alaska has entered into contracts for the interstate sale of its royalty gas which include provisions permitting the State to subsequently withdraw the gas from the interstate market for use within the State. These withdrawal provisions are sanctioned by Section 13(b) of the Alaska Natural Gas Act of 1976.

However, as discussed in the Jurisdiction and Financing sections of this Initial Decision, substantial difficulties arise from the State's asserted right to commit its gas to interstate use with one hand and take it back with the other. The mere prospect of withdrawal imperils the financeability of an Alaskan gas project; actual withdrawal would idle downstream facilities and in turn produce adverse cost impacts.

Moreover, when the Section 13(b) withdrawal provision is coupled with the Act's "equal access" provision, 1/ it becomes readily apparent that the statute in its present form could operate to confer a substantial indirect subsidy to the State. Assuming that the project could be financed and completed, that Alaska's interstate customers (El Paso Natural, Tenneco Alaskan, and Southern) participated in the equity financing with consumer guarantees, and that Alaska thereafter found an intrastate use for its royalty gas, the consumers of the three customer companies would have risked their dollars to help finance the project, only to see consumers in Alaska reap the reward.

For the reasons stated herein, the Presiding Judge respectfully suggests that the Commission, in its recommendation to the President, give consideration to the desirability of amending the Alaska Natural Gas Act of 1976 to delete therefrom Sections 13(a) and 13(b). Absent deletions of these two provisions, direct and total U.S. government guarantees would appear to be the only feasible method of financing.

1/ Section 13(a) of the 1976 Alaska Natural Gas Act would deny the Commission the power to limit access to the transportation system to shippers participating fairly in its equity financing. It is questionable whether the proposal to finance an Alaskan project with consumer guarantees is possible in the face of this statutory provision.

I don't question the wisdom of the State seeking a confrontation with the FPC over jurisdictional matters but the timing and circumstance could hardly have been worse.

The avowed intention of the State to gain a trans Alaska route with access to its own gas has not been pursued with a vigorous policy, nor has there been a determined exploration of ways and means to gain those goals. We do not believe the Administration has demonstrated the ability to comprehend the multitude of problems remaining nor the will to take affirmative action in the short time left before a final decision is made.

Our hopes rest with this Legislature to provide the leadership so lacking in the hearings up to now.

Of the twenty-four (24) states which intervened, Alaska is the only state which supports El Paso. Only two gas line companies support El Paso; Tenneco and Southern. Intermountain Gas (Idaho) alone supports Alacan. The large majority of States, gas transmission and distribution companies support Arctic Gas. The FPC staff report and Judge Litt's initial decision recommend Arctic.

Perhaps the Governor may be correct that the political lobbying of Tenneco and Southern will tip the decision by the President and Congress in favor of El Paso over the immense weight of Arctic Gas support.

But we aren't willing to rest with those odds, nor do we think the people of Alaska are.

We know there are ways that the State can take effective action, that there are ways to demonstrate our concern for the National interest, and a cost-and-benefit plan which rebounds to all consumers.

Judge Litt pointed the way a number of times in his decision and, in one instance, hung out the beacon of two lights in the old North Church, if by sea.

AGO 532976

On pages 361 - 362 "It immediately became apparent that the only traditional credit-worthy parties involved in this proceeding whose added credit could permit conventional financing were the two direct financial beneficiaries of Alaskan natural gas sales -- the producers and the State of Alaska. Despite the billions each will reep from the sale of Prudhoe Bay hydrocarbons, neither has shown any particular interest in investing in a transportation system to market gas or otherwise assist in its financing."

Page 363 - 364 THE BEACON

As far as the State of Alaska is concerned, there is no record evidence that other states have participated in financing this type of gas pipeline project. It is not that financing utility and industrial projects through municipal bonds, direct ownership of generating facilities (e.g., New York), or forgoing certain taxes is unknown to states seeking to ensure an expanding economic base. Given the avowed intentions of the State to invest its revenues and the high rate of return suggested here for either equity or debt, the State may see this as a better investment than it can receive elsewhere. 2/ If, in addition, tariffs require the ultimate consumers to shoulder full debt service responsibility and the bonds issued achieve debt ratings satisfactory to the New York State Insurance Commission, they would probably also satisfy the State of Alaska's investment trust fiduciary. 1/ Nevertheless, such investments are voluntary, and the State of Alaska has not volunteered.

2/ While it might be unkind to suggest, there is a likelihood that the State might be willing to aid El Paso if it appeared that such offer might tip the choice towards the State's first love. The State's excellent presentation, through a range of perceptive and knowledgeable witnesses, does not permit ignoring that such an obvious suggestion may be made at a propitious time in the decisionmaking process.

This is the "Open Sesame" for Alaska. Either equity or debt participation, or both may tip the decision.

Because the State and producers have not come forward as a creditworthy party to assist, Judge Litt

proposed Federal Financial Participation legislation:

> "The Treasury Department should be granted statutory authority necessary and appropriate to accomplish whatever Federal participation in the Alaska gas project financing is ultimately determined to be required in the public interest."

Replete through the decision, especially in the section of Economics, Socio-Economics, Cost Allocation, and Financing and Tariffs are statements that Federal guarantees will be required, that ultimate costs will be borne by the consumers with taxpayer backing in order to offset the risks so that money can be raised in the financial community.

We propose the establishment of an Alaskan Gas Authority for ownership of the gas pipeline, production, and terminal facilities.

Precedents to such an Authority are everywhere. To mention a few, Tacoma and Seattle generate power for the lowest electrical rates in the nation, the Public Utility Districts along the Columbia River furnish power throughout the Northwest and sell 17 billion kilowatts to California annually, the Seattle Port Authority operates the seaport of the city as well as Sea-Tac Airport. States have built dams, gas, coal, and oil generation and transmission systems; they have constructed bridges, toll highways, airports, and marine transportation systems. In our own state we operate three international airports and a ferry system. Nationally, the T.V.A., dams, etc.

Whenever the needs for energy and transportation have been perceived and an opportunity is available to meet those needs, government--local, municipal, county and state--have responded by guaranteeing the means to meet those needs.

In our hour of greatest energy need that is what Alaska must do.

If we are to gain our own energy independence we must act resolutely to prove we have the will and determination to manage our own destiny.

The magnitude of this proposal is immense, but not at all insurmountable. A number of financial experts representing major bond firms and banking institutions have stated it would be a joy to participate in the underwriting of tax exempt revenue bonds.

As an illustration, let us incorporate for $6,000,000,000.00 in tax revenue bonds and use 6% as the effective rate of interest. (Incidentally, the City of Valdez sold the first $262 million bond offering on Feb. 7 at a 5.94% rate)

At 6% the maturity payback will be:

$11,658,000,000.

$ 5,658,000,000. interest

At 10% (page 269 "The applicants' financial witnesses estimate a debt cost of approximately 10%, based on a Baa bond rating, and the applicants seek 15% to 17% as an after-tax return on equity.")

$16,432,800,000. maturity pay back

$10,432,800,000. interest.

Thus, the first savings on this huge debt would approximate $4,774,800,000. which will be reflected in a lower tariff paid by our fellow consumers in the lower 48.

But there is even a greater ancilliary savings to be achieved for another lowering of tariffs. All of the applicants are seeking 15-17% profit as an after-tax return on equity.

The combined U.S. and Alaskan income tax rate of 52.89% requires pre-tax revenues of $212. to provide $100. in after tax income. Combined taxes in Canada would require $221. of revenue.

Taken together these are very substantial cost-benefits to the American consumer.

Another major savings will occur in State ownership and construction of the gas conditioning plant at Prudhoe Bay. Page 1, Appendix C --- " Preliminary estimates made several years ago indicate the plant will require 4 - 6 years to design, fabricate, and construct, and will cost about $ 1 billion (1975 costs)"; with the financing assured (not having to wait until the entire transmission system has been funded) work could proceed expeditiously, assuring quicker delivery and saving whatever the annual inflation rates would be.

There are other beneficial reasons including State responsibility of maintaining the integrity of construction and operation of the gas pipeline. The State also has the greatest interest in the maximum utilization of oil and gas from the Prudhoe field as well as the undiscovered reserves in the Beaufort-Chuckchi Seas.

How may we expect the Federal Power Commission to consider such a proposal?

Judge Litt will have found his credit-worthy party capable of providing the financing to guarantee the feasibility of the project. There will be no need to seek legislation for Federal guarantees. An updated cost-benefit analysis will reveal that the all-Alaska pipeline will rebound to all consumers. Because of the State's active participation, the remainder of the financing will be made measurably easier. Thus, it may be the "offer to tip the choice toward the State's first love."

We believe that President Carter, the Congress and our fellow Americans will regard Alaska with new respect as a full partner in the Union, not the new kid about to inherit great wealth but unwilling to share in the National interest. We believe that President Carter and Congress will understand our concerns and desires to become more self-sufficient and better able to provide for our people. We

believe President Carter and the Congress will look kindly upon us when it comes time to make the final decision.

SCOMM

#14:6

PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

NATURAL GAS CONDITIONING AND PIPELINE DESIGN

A Technical Primer for Non-Technicians,
With Special Reference to Hydrocarbons from Prudhoe Bay
and the Alaska Highway Gas Pipeline

BY CONNIE C. BARLOW

Juneau, Alaska
March 11, 1980

Prepared for the State of Alaska
Department of Natural Resources

ARLON R. TUSSING & ASSOCIATES, INC.

AGO 532982

TABLE OF CONTENTS

		Page
	TABLE OF CONTENTS	i
	INTRODUCTION	ii
I.	THE BASICS OF PIPELINE DESIGN	1
	A. Hydrocarbon Characteristics	1
	1. Chemistry	1
	2. Heating values	2
	3. Phase characteristics	4
	B. Gas Versus Liquids Pipelines	5
	C. Pressure Specifications	6
	D. Hazards of Two-Phase Flow	9
II.	GAS COMPOSITION DECISIONS	12
	A. Introduction	12
	B. Phase Diagrams	13
	C. The Relationship Between Gas Composition and Upset Conditions	16
	D. Carbon Dioxide Content	19
	1. The effect of carbon dioxide on hydrocarbon dewpoint	20
	2. The effect of carbon dioxide on pipeline corrosion	20
	3. The effect of carbon dioxide on downstream gas systems	22
	4. The effect of carbon dioxide on project economics	23
	E. Volumes of Gas and Gas Liquids Available for Shipment	25
	1. Reservoir production rates	25
	2. Gas Composition changes	26
	3. North Slope fuel requirements	28
	4. Shipping intermediate hydrocarbons through TAPS	34

INTRODUCTION

The State of Alaska faces a variety of questions related to the proposed Alaska Highway Gas Pipeline which combine highly technical engineering considerations with important public policy issues. These questions include:

— location, design, and ownership of the gas conditioning plant,
— choice of fuel for North Slope operations, and
— pressure and diameter specifications of the pipeline itself.

Some grasp of the engineering jargon and basic principles is essential if Alaska's elected officials and agency staff are to identify the State's priorities correctly: What issues really affect the State's interests, and to what extent? Which, if any, of the other parties --- the producers, gas shippers, and federal authorities --- are likely to share the State's interests in each of these questions, and to what extent? How much can Alaskans depend on others, therefore, to look after the State's interests? How formidable is opposition likely to be to the State's position, and what burdens would the State's demands impose on others? Overall then, where should the State realistically direct its efforts?

This report, in itself, will not answer those questions; it should, however, make State decision-making a bit easier. We have tried to distinguish scientific facts from matters of differing engineering judgment, and both from differences of economic interest; and to present the range of opinions fairly. Our goals have been to develop a primer on gas conditioning and pipeline transportation that is relevant to Alaskans, speaks to non-technicians, yet is precise and complete enough to survive the scrutiny of experts.

AGO 532984

Special thanks goes to Harold R. Galloway and James L. Shanks, Jr. of Exxon, D. J. Pritchard of Sohio, W. S. Dickinson of Arco, A. J. Green of Westcoast Transmission, Robert M. Maynard of the State of Alaska's Department of Law, and Robert H. Loeffler of Morrison & Foerster, the State's Washington counsel.

AGO 532985

I. THE BASICS OF PIPELINE DESIGN

A. HYDROCARBON CHARACTERISTICS

1. Chemistry

The crude oil and natural gas produced from Alaska's Prudhoe Bay reservoir are mixtures of hydrocarbons (compounds of carbon and hydrogen), plus impurities like water and carbon dioxide. The most fundamental classification of hydrocarbon compounds is in terms of the number of carbon atoms in each molecule.

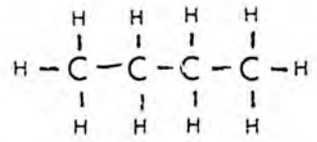
TABLE 1

Reservoir Fluid	Compound	Chemical Formula	Abbreviation	Commercial Product
natural gas	methane	CH_4	C_1	dry gas
	ethane	C_2H_6	C_2	natural gas liquids (NGLs) or condensate
	propane	C_3H_8	C_3	
	butane	C_4H_{10}	C_4	
crude oil	pentane	C_5H_{12}	C_5	natural gasolines, naphtha, or pentanes-plus
	hexane	C_6H_{14}	C_6	
	heptane	C_7H_{16}	C_7	
	octane	C_8H_{18}	C_8	oils, waxes, tars
	-	-	-	
	-	-	-	
	etc.	C_nH_m	C_n	

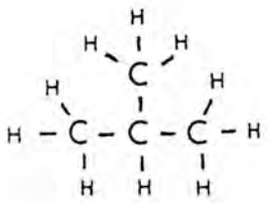
Hydrocarbons containing more than three atoms of carbon in each molecule have several different configurations. These forms or "isomers" often have different physical characteristics. For example, Table 2 shows that "normal" butane [n-butane] can remain in a liquid state in the TAPS oil pipeline at higher temperatures than can the branched isomer "iso" butane [i-butane].

AGO 532986

FIGURE A: NORMAL AND ISO-BUTANE



"normal" (n) butane



"iso" (i) butane

2. Heating values

The heating value of each hydrocarbon reflects, in part, the number of carbon atoms that will oxidize as the fuel is burned. Table 2 shows the heating values of light hydrocarbons and their isomers, both in liquid and vapor states. Normally, heating values are expressed in gross BTU's[1], also called the higher heating value. The expected heating value of gas that will be shipped through the Alaska Highway gas pipeline (or Alaska Natural Gas Transportation System [ANGTS]), for example, is invariably expressed in gross terms.

The lower heating value, measured in net BTU's, serves a very limited function, primarily in describing the fuel requirements for various types of machinery and processes. Net BTU's for hydrocarbon vapors have beer used by some parties involved in the design of the North Slope gas conditioning plant; Table 2, therefore, includes net measurements for hydrocarbon vapors.

The difference between gross and net BTU's is highly technical. The reader need only remember that (1) unless specifically designated as net BTU's, one can assume that all heating value data represent gross measurements; and (2) like apples and oranges, the two should never be confused or mixed in heating value calculations.

---

1) A British Thermal Unit (BTU) represents the amount of heat required to raise the temperature of one pound of water by one degree F.

TABLE 2

HYDROCARBON	VAPOR HEATING VALUE		LIQUID HEATING VALUE
	BTU/scf* gross	BTU/scf net	BTU/barrel** gross
Methane	1010	909	2,512,818
Ethane	1769	1618	2,771,916
Propane	2518	2316	3,824,730
i-butane	3253	3001	4,158,924
n-butane	3262	3010	4,325,538
i-pentane	4000	3698	4,569,180
n-pentane	4010	3708	4,624,284

Source: Natural Gas Processors and Suppliers Association, Engineering Data Book, 1979.

* A Standard Cubic Foot (scf or cf) is the amount of gas that would fill a cubic foot of space at 60 degrees F. and standard atmospheric pressure. The following abbreviations are often used to represent large volumes:

Mcf = thousand cubic feet
MMcf = million cubic feet
bcf = billion cubic feet
Tcf = trillion cubic feet

** One barrel = 42 U.S. gallons.

AGO 532988

3. Phase characteristics

The more carbon atoms a molecule contains, the heavier it is. The heaviness of a particular hydrocarbon will influence whether it exists in a vapor or liquid phase at various combinations of temperatures and pressures. Table 3 shows the boiling points of light hydrocarbons. At temperatures below the boiling point, a hydrocarbon is a liquid; above, it is a vapor.

TABLE 3

SUBSTANCE	MOLECULAR WEIGHT	BOILING POINT (F.) [at atmospheric pressure]
C_1	16.043	-258.69
C_2	30.070	-127.48
C_3	44.097	- 43.67
i-C_4	58.124	+ 10.90
n-C_4	58.124	+ 31.10
i-C_5	72.151	+ 82.12
n-C_5	72.151	+ 96.92
n-C_6	86.178	+155.72
n-C_7	100.205	+209.17
n-C_8	114.232	+258.22
CO_2	44.010	-109.30

Source: Natural Gas Processors and Suppliers Association, Engineering Data Book, 1979.

Oil is now injected into the Trans Alaska oil pipeline (TAPS) at a temperature of 142 degrees F. At times, the oil may experience pressures enroute as low as normal atmospheric conditions. Under these circumstances, Table 3 shows that hexanes (C_6) and all heavier hydrocarbons would always remain in a liquid phase during shipment through TAPS. Mixtures of heavy hydrocarbons also have the ability to carry small quantities of C_5 and even C_4 without vapor formation. On the other hand, mixtures of the lightest hydrocarbons (C_1, C_2, and C_3) remain in the vapor phase even in a chilled gas pipeline, and can likewise absorb some C_4 and possibly C_5 without condensation.

The question of how much of these intermediate hydrocarbons (C_4 and C_5) will be carried as vapors by ANGTS, shipped as liquids in TAPS or in a third "gas-liquids" pipeline, used for fuel on the North Slope, or routed to some other purpose, remains open. Resolution of this issue depends upon a whole array of decisions, including pressure and temperature specifications for operation of both the gas and oil pipelines, the amount of CO_2 permitted in the gas pipeline, the choice of gas conditioning process, the kinds and amounts of fuel used in the field and for pipeline pumps and compressors, and oil and gas production rates. This report examines each of those factors, their relationships, and the ultimate effect such decisions may have on the kinds and amounts of hydrocarbons transported.

B. GAS VERSUS LIQUIDS PIPELINES

Pipelines carrying hydrocarbons in a liquid phase (such as the TAPS oil line and a proposed gas liquids line) use pumps to move these materials. Pipelines designed for gaseous hydrocarbons, such as the proposed Alaskan Northwest pipeline, use compressors. The difference is subtle, but important.

In liquids, the individual molecules are packed tightly together and, for all practical purposes, cannot be compressed into a smaller volume. Instead, as more molecules are pumped into a pipe, they shove the mass of hydrocarbons in front of them into the next pump station, like a train of boxcars pushed from behind. Naturally, the greater the distance (and the greater the rise in elevation) between pump stations, the greater is the horsepower required.

AGO 532990

Gaseous hydrocarbons, like all vapors, are compressible. Each compressor station on a gas pipeline draws vapor into its inlet at a relatively low pressure (called the suction pressure), compresses it into a smaller volume, and expels it at a higher pressure, known as the discharge pressure. As the gas expands between the outlet of one compressor station and the inlet of the next, pressure again falls, and this pressure drop or differential causes the gas to flow through the pipe. It is the discharge or operating pressure, being the greatest pressure experienced by the pipeline, that is limited by the strength of the steel pipe.

C. PRESSURE SPECIFICATIONS

Pressure drop is usually measured as a ratio to distance, psi per mile.[2] Being the stimulus for gas movement through a pipeline, it is therefore one of several factors that determine how much gas can be transported each day. Throughput is determined by the following components:

(1) Discharge pressure, (2) Suction pressure, and (3) Compressor Station spacing determine the pressure drop, and thereby the SPEED of flow, while

(4) Pipeline diameter determines the AMOUNT of gas that can be shipped through a pipeline at any given speed.

---

2) Pressure is measured in pounds per square inch (psi). Objects at sea level are subjected to an atmospheric pressure of about 14.7 psi (which results from the weight of several miles of air resting on the earth's surface). Instruments designed to measure artificially induced pressures like those inside gas pipelines, record or guage pressures in excess of this ever-present atmospheric pressure (psig). Absolute pressure measurements include the 14.7 psi exerted by the atmosphere (psia). Hence, 1680 psig is the same as 1694.7 psia.

Of these four variables, a pipeline's diameter and the maximum discharge pressure that it can accomodate (that is, the pipeline's operating pressure) are the only ones that cannot be altered once the pipe is laid. The other two can, in theory, be modified to accomodate changes in throughput: Throughput can be increased either by adding more compressor stations or by increasing the suction power of existing compressors.

There are, of course, practical and economic constraints on the number of compressor stations that can be added. Likewise, the suction power of compressors experiences a marked drop-off in efficiency beyond a given range of compression ratios.

The compression ratio is the ratio between a compressor's discharge pressure and its suction pressure. Compression ratios are generally in the vicinity of 1.2 to 1.3. Table 4 shows the suction pressures corresponding to a compression ratio of 1.25 at four operating pressure levels heretofore considered for the Alaskan and Canadian sections of the Alaska Highway Gas Pipeline.

TABLE 4

Operating pressure	Efficient Delivery Pressure
1680 psig	1350 psig
1440 psig	1150 psig
1260 psig	1010 psig
1080 psig	860 psig

The National Energy Board (NEB) has approved construction of a 1080 psig 56 inch diameter pipeline in Canada. Though some contention still exists on the matter, the Federal Energy Regulatory Commission (FERC) has approved the design proposed by the pipeline sponsor, Northwest Alaskan,

AGO 532992

with an operating pressure of 1260 psig for a 48 inch pipeline in Alaska. EXXON and the State of Alaska have advocated higher operating pressures, such as 1680 psig (or even 2160 psig for a 42 inch diameter pipe). ARCO at one time proposed a compromise pressure of 1440 psig.

The controversy over the pipeline's operating pressure and diameter stems, in part, from a recognition that manipulating discharge and suction pressures or even building more compressor stations after the pipe is laid are not necessarily the most economic or practical responses to future changes in throughput. For these reasons, designers must choose pipeline diameter and wall thickness specifications and compressor station locations that reflect a realistic judgment of likely throughputs over the life of the facility. FERC and Northwest concluded that a 1260 psig 48" diameter pipeline is the most efficient and economic compromise for the volume of gas expected from the main Prudhoe Bay reservoir (about 2.0 bcf/day). However, they agree that at a throughput somewhere between 2.6 and 2.9 bcf per day, a 1680 psig line would make more sense. ["Report of the Alaskan Delegate on the System Design Inquiry", FERC, May 17, 1979; p. 27.]

Unfortunately, the additional volumes of North Slope gas likely to become available during the expected 20 or 25 years of gas pipeline operations are both uncertain and controversial. No one can know with confidence whether the 1260 psig system ultimately will prove to be the best choice.

A related issue that must be addressed during engineering design is the need for crack arrestors. Even if a pipeline's wall thickness is sufficient to withstand its own INTERNAL gas pressures, pipeline designers have to safeguard against the effects of catastrophic EXTERNAL forces --- such as a misguided bulldozer or a saboteur's bomb.

AGO 532993

Obviously, localized damage cannot be prevented entirely. In a large diameter, high pressure gas pipeline (unlike TAPS), however, even a small injury to the pipe can result in a fracture that spreads explosively up and down the system, perhaps destroying pipe for tens of miles. Girdling the pipe at regular intervals with sturdy metal crack arrestors is one solution.

Virtually everyone agrees that a 1680 psig, 48 inch diameter pipeline must be equipped with crack arrestors. Opinions, however, vary with respect to a 1260 psig system. Since crack arrestors are a significant expense, no conclusive judgment about the relative economic advantages of a 1260 psig system can be reached in the absence of a decision on the need for crack arrestors.

Probably the biggest source of controversy with respect to the selection of an operating pressure for the Alaska Highway Gas Pipeline centers, however, on the ability of higher pressure pipelines to carry heavier hydrocarbons without risking two-phase flow.

D. HAZARDS OF TWO-PHASE FLOW

Long-distance pipelines must be designed to carry hydrocarbons either in a vapor phase (like the Northwest pipeline) or in a liquid phase (like TAPS and the proposed gas liquids line). Transporting vapors and liquids together in one stream results in a condition called two-phase flow. The dangers of two-phase flow are as follows:

(1) General problems of two-phase flow. A pump or compressor is designed to operate on material of a certain density. Encountering bubbles of vapor in a stream that should be totally liquid is a little like swinging a bat at a baseball and missing; while coming across droplets or, worse yet, big "slugs" of liquid in a stream that should be all vapor is like being hit with a barrage of snowballs. Either event can be rather jarring to the system.

(2) "Surge" and "slug" problems of two-phase flow. If droplets of liquids condense in the vapor stream, they tend to settle and accumulate in low spots along the pipeline, constricting the room available for vapor flow. As the amount of trapped liquid grows, pressure builds --- eventually forcing the liquid up and over the next hump. Large slugs of dense liquids are, therefore, accompanied by an uneven or surging flow of fluids. Extreme surging conditions can cause severe damage when a slug enters a compressor station.

It should be noted that some pipelines are intentionally operated in two-phase flow conditions, while gathering "wet" (unconditioned) gas in the field, or bringing gas from offshore wells to shore-based facilities. Usually, however, these pipelines are quite short and undersized; no pumps or compressors that could be damaged by surging slugs are located along the way. In fact, some offshore pipelines for which slug formation cannot be avoided empty onshore into several miles of convoluted pipeline called slug catchers. Here the tremendous force of the slugs is dissipated, and the liquid itself is "scrubbed" out of the gas, prior to entering pumping, processing, or compressing facilities.

Designers and operators of long-distance gas pipelines, like the ANGTS which has several compressor stations and many ups and downs enroute, can take a variety of actions to reduce the hazards of two-phase flow. They can:

* Avoid building an oversized line. One way to prevent the accumulation of liquids at low points along the line is to ensure that vapors flow at a high speed. This means choosing a pipeline diameter appropriate to the expected throughput, maintaining a high pressure drop, or both. If a system is designed to carry an average of 3.0 bcf/day and only 2.0 bcf/day is available for shipment, pressure drop would have to be reduced in order to ensure a steady flow of the smaller volume of gas. The result is a slower movement of gas and, hence, a greater danger of slug formation and surging.

* Equip the line with drains. Valves to drain off accumulated liquids can be inserted in low spots along the pipeline.

* Ensure against sloppy pipeline operations. If drains are installed, they must be used properly. If adequate drainage is impractical, the line should receive more frequent "pigging" (insertion of a solid object, or pig, which pushes accumulated liquids out ahead of it). If throughput is raised or lowered, changes in the input and output pressures must be synchronized. If the line is shut down temporarily, special care must be taken when operations resume to prevent the passage of entrained liquids that may have formed during the outage. For these reasons, no matter how free of droplets the sales gas may be when it enters the pipeline, sloppy operations can result in dangerous two-phase flow conditions.

AGO 532996

None of the above precautions are of much use in long-distance pipelines, however, unless pipeline operators also:

* Restrict the volume of heavy hydrocarbons. Pipelines must transport only hydrocarbon mixtures that pose no threat of condensation at any combination of temperatures and pressures likely to be encountered under either normal or abnormal conditions. Determining the optimum mixture is rather complicated, as the next chapter shows.

II. GAS COMPOSITION DECISIONS

A. INTRODUCTION

In designing a gas transportation system, everything seems to affect and be affected by everything else. We have seen, for example, that decisions about pipeline diameter, operating pressure, suction pressure, and compressor station spacing are all interdependent. Further, these specifications cannot be set intelligently except with reference to some volume or range of volumes for expected throughput. The same holds true with respect to determining the optimum chemical composition of pipeline quality gas; that is, the relative amounts of methane, ethane, propane, butane, heavier hydrocarbons, carbon-dioxide, water, and sulphur compounds in the gas delivered to the pipeline.

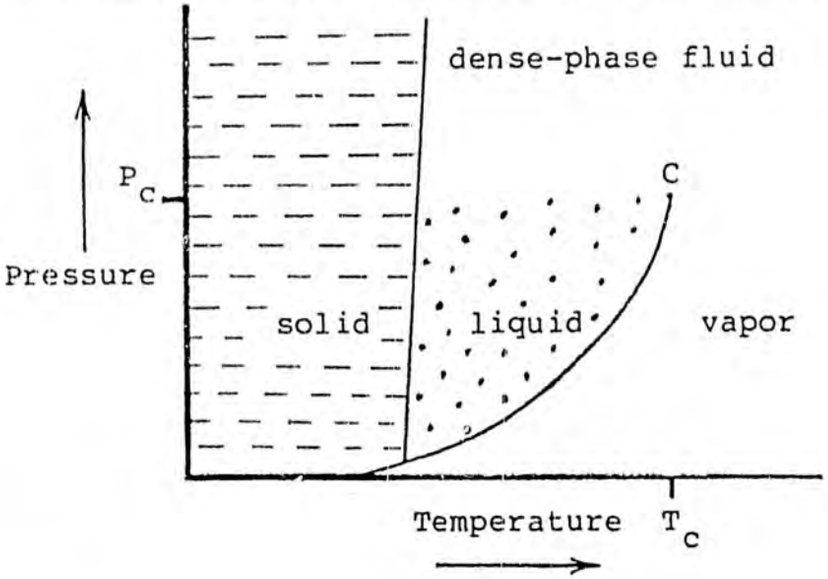
AGO 532997

Temperature and pressure are the two factors that determine whether any particular hydrocarbon or mixture of hydrocarbons will be present in a vapor or in a liquid phase. Thus, pipeline designers must choose a balanced combination of pressure, temperature, and composition specifications that will ensure safe operations and avoid two-phase flow.

B. PHASE DIAGRAMS

Almost everyone is familiar with "bottle gas" -- pressurized containers of propane and butane used to fuel appliances in isolated homes, mobile homes, and recreational vehicles, and for camping stoves and lanterns. The propane or butane exists as a liquid inside the containers, but vaporizes upon release. Heavier hydrocarbons like gasoline and diesel fuel are liquids at atmospheric pressures and temperatures but vaporize when heat is added. These are all examples of phase changes. Each hydrocarbon has its own phase diagram, like that of Figure B, which shows how changes in pressure and temperature affect its physical characteristics.

FIGURE B: PHASE DIAGRAM OF A PURE SUBSTANCE



AGO 532998

Notice first, that four phases are shown: solid, liquid, vapor, and something called dense-phase fluid. Unlike the other phases, it is hard to pinpoint where the dense phase fluid starts and ends; but we do know that it occurs only at extremely high pressures. It is also difficult to describe: A dense-phase fluid is dense like a liquid, but compressible like a vapor. And unlike solids, liquids, and vapors, which we all encounter in our daily lives, dense-phase fluids exist only deep inside the earth and within artificially created environments like natural gas pipelines.

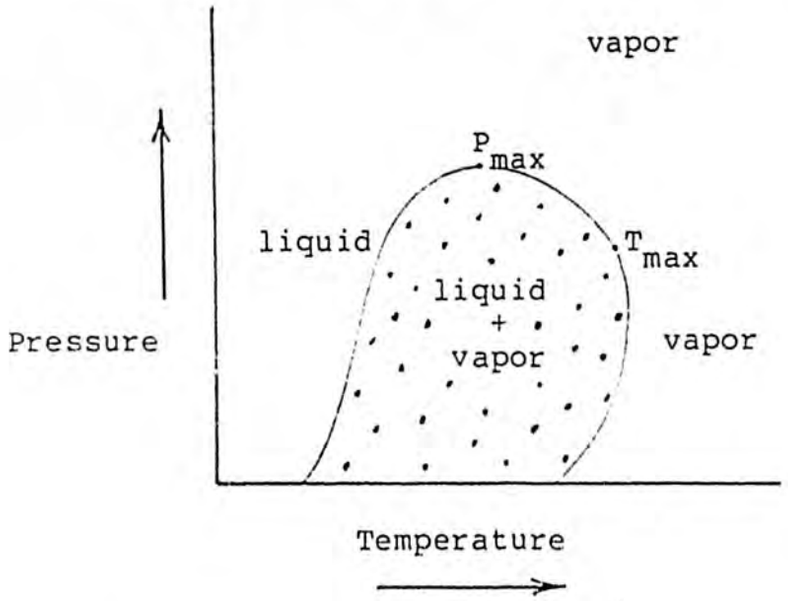
While this high pressure phase is technically a creature unto itself, for our purposes there is no practical distinction between such fluids and vapors, and we shall generally use the word vapor for both.

Point C in Figure B is called the critical point. For any pure substance, no liquid can exist at pressures above the critical pressure (P_c) --- no matter how far the temperature drops. Likewise, no liquid can exist at temperatures beyond the critical temperature (T_c) --- again, no matter how much pressure is exerted.

Unfortunately phase diagrams of hydrocarbon MIXTURES, like that of Figure C, are more complicated to read and understand than are the diagrams of pure substances. For volumes containing only a single hydrocarbon type, two phases will coexist only at pressure-temperature combinations represented by the thin line separating liquid and vapor phases. But for hydrocarbon mixtures, the net effect of all the individual phase diagrams is a tongue-shaped region or phase-envelope in which both gas and liquid states are present. To avoid two-phase flow in pipelines, therefore, any combination of temperature and pressure falling

inside the phase envelope must be avoided. Liquids pipelines must operate to the left of the phase envelope, while gas pipelines must function above or to the right of it.

FIGURE C: PHASE DIAGRAM OF A MIXTURE



The temperature and pressure combinations that delineate the right and upper boundaries of the phase envelope are called dewpoints, marking the conditions at which droplets first begin to appear in a vapor as the temperature or pressure falls. The combinations along the left side of the phase envelope are called bubblepoints, marking the conditions at which bubbles of vapor first appear in a liquid. TAPS engineers, therefore, worry about bubblepoints, while ANGTS engineers fret over dewpoints. The next chapter will examine how engineers use phase diagrams to determine what mixtures of light hydrocarbons can be handled safely in ANGTS.

THE RELATIONSHIP BETWEEN GAS COMPOSITION AND UPSET CONDITIONS

While the choice of operating (or discharge) pressure has thus far dominated the discussion of two-phase flow, the operating pressure in itself does not limit the allowable range of gas mixtures. Likewise, the temperature at which gas is discharged from each compressor station is not the limiting factor. Instead, project engineers concern themselves with the combination of pressure and temperature conditions that would occur in a system upset.

As the term implies, upset conditions are those that occur when the system malfunctions. Engineers study upset conditions in order to forecast the most troubling combination of temperature and pressure (from the standpoint of two-phase flow) that vapors moving through the gas pipeline are likely to encounter. Since ANGTS will be designed to carry light hydrocarbons in a high pressure vapor phase (more precisely, a dense-phase fluid), upset conditions denote the LOWEST expected combinations of temperature and pressure.

How are upset conditions determined? First, the normal operating window of pressures and temperatures must be calculated. This represents the range of conditions likely to occur, assuming that the system is functioning properly. The lowest pressure experienced under these normal conditions is the suction pressure, which occurs at the entrance to each compressor station.

Calculating the lowest temperature likely to occur under normal operating conditions is more difficult. It depends, in part, upon the temperature at which gas is ejected from the compressor stations. Interestingly, the Canadian pipeline segments south of Whitehorse have an

advantage on this point. Compressor stations in Alaska must discharge gas with a temperature no higher than 32 degrees F., in order to prevent melting of permafrost through which the buried pipeline is laid. However, south of Whitehorse permafrost is a relatively minor problem and discharge temperatures, therefore, can be higher.

The lowest limit of acceptable gas temperatures is a function of the pipe's ductility and other physical characteristics. In the present preliminary design, this lower limit is -10 degrees F. Minimum normal operating temperatures are, in turn, determined mainly by the Joule-Thompson cooling effect: a gas naturally falls in temperature as it expands between its discharge from one compressor and its delivery to the next. The lowest operating temperature also depends upon what ground or air temperatures the designers expect to occur along the pipeline route. As long as the pipeline in Alaska is buried, the temperature it encounters will stay around 10 degrees F. throughout the year. If any section of the pipeline is constructed above ground, however, the cold Arctic winters become a real concern.

Once pipeline designers determine the normal operating window of temperatures and pressures, they can forecast the effects of specific malfunctions. Calculation of the resulting upset conditions reflects the designer's judgment as to WHICH malfunctions must be accomodated. Generally, upset conditions that have been discussed with respect to the Alaska gas pipeline reflect an assumption that the worst case would be one in which a single compressor station is totally shut down for repairs. But the implications of this assumption depend also on WHICH station is out of service. Moreover, the worst conditions under which the system will operate are also a function of how much the pipeline's designers and operators are prepared to reduce throughput in case of an upset: Will they simply route the

the gas past the ailing station without increasing the suction capability downstream? Or will the next station be forced to work harder in an attempt to keep throughput from falling too severely? Again, determining how much the operator can manipulate suction pressure at the downstream station depends upon the minimum stress temperature of the steel pipe (-10 degrees F, as we mentioned previously), the mechanical limitations of the machinery, and the dewpoint characteristics of the gas itself.

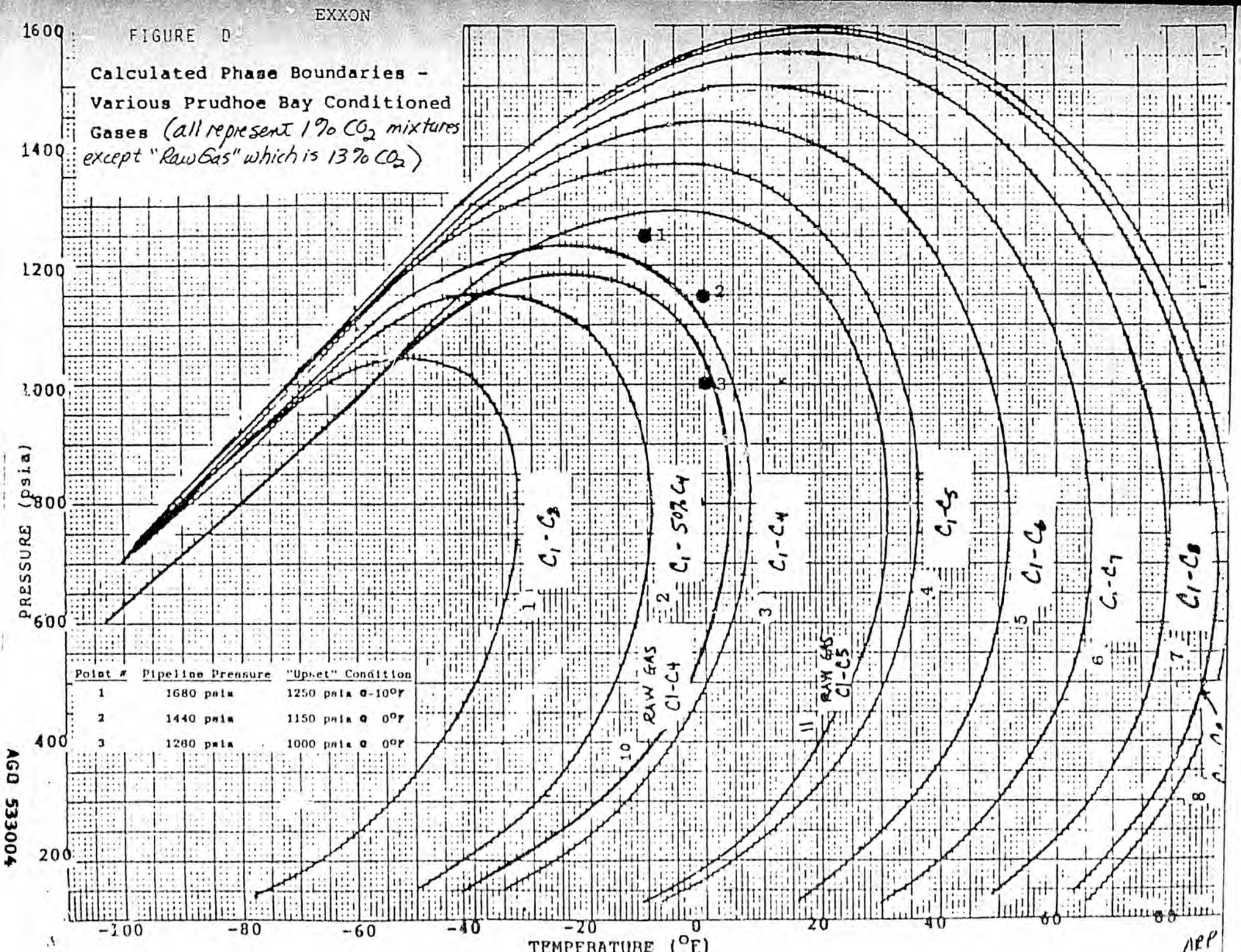
Figure D plots the temperatures and pressures of assumed upset conditions for the several pipeline operating pressures under consideration, and illustrates how close these points come to the two-phase flow conditions of various North Slope hydrocarbon mixtures. While an understanding of the basic physical principles reviewed here is important, no one can precisely assess the system's upset temperatures and pressures except in conjunction with detailed engineering and contingency plans. This explains why different parties have projected different upset conditions for ANGTS.

Figure D shows, for example, why upset conditions for the Canadian pipeline sections are of no real concern with respect to choice of gas composition. Even though the Canadian pipeline will function at a lower operating pressure (1080 psig, with a corresponding upset pressure of about 860 psig), it will have a significantly higher upset temperature (around 30 to 40 degrees F.) because the lack of permafrost south of Whitehorse permits higher compressor discharge temperatures. If one plots the intersection of 860 psig and 35 degrees F., it is evident that the design of the Alaska portion of the pipeline will be what limits the volume of intermediate hydrocarbons shipped through the entire system.

EXXON

FIGURE D

Calculated Phase Boundaries - Various Prudhoe Bay Conditioned Gases (all represent 1% CO_2 mixtures except "Raw Gas" which is 13% CO_2)



Point #	Pipeline Pressure	"Upset" Condition
1	1680 psia	1250 psia @ -10°F
2	1440 psia	1150 psia @ 0°F
3	1280 psia	1000 psia @ 0°F

AGD 533004

MPP

EXXON

VARIOUS PRUDHOE BAY CONDITIONED GAS COMPOSITIONS
(Mole Percent)

Component	Unconditioned Separator Off-Gas	① C_1-C_3	② C_1-50%C_4	③ C_1-C_4	④ C_1-C_5	⑤ C_1-C_6	⑥ C_1-C_7	⑦ C_1-C_8	⑧ C_1-C_8	⑨ C_1-C_9	⑩ Off-Ga C_1-C_4
N_2	0.484	0.564	0.559	0.554	0.551	0.550	0.549	0.549	0.549	0.549	0.48
CO_2	12.659	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	12.773
C_1	74.706	87.053	86.296	85.554	84.964	84.818	84.742	84.695	84.679	84.676	75.382
C_2	6.428	7.491	7.426	7.362	7.311	7.299	7.292	7.288	7.287	7.287	6.486
C_3	3.340	3.892	3.859	3.826	3.799	3.793	3.789	3.787	3.786	3.786	3.370
i-C_4	0.450	--	0.260	0.515	0.512	0.511	0.511	0.510	0.510	0.510	0.454
n-C_4	1.038	—	0.600	1.189	1.181	1.179	1.178	1.177	1.177	1.177	1.04
i-C_5	0.217	—	--	—	0.247	0.247	0.246	0.246	0.246	0.246	--
n-C_5	0.383	—	—	--	0.435	0.435	0.434	0.434	0.434	0.434	--
C_6	0.148	--	--	--	--	0.168	0.168	0.168	0.168	0.168	—
C_7	0.081	—	—	--	--	--	0.091	0.092	0.092	0.092	--
C_8	0.047	—	--	--	--	—	—	0.054	0.054	0.054	--
C_9	0.016	--	—	--	--	—	—	--	0.018	0.018	--
C_{10}	0.003	--	—	--	--	--	—	--	—	0.003	--
Molecular Wt.	22.7	18.5	18.8	19.2	19.5	19.7	19.8	19.8	19.8	19.9	22.2
Heating Value (Btu/cf*)	1027	1095	1113	1131	1150	1156	1160	1163	1164	1164	996

*Gross, Wet, Actual @ 60°F., 14.73 psia

3-7-78

AGO 533005

Alaska state officials thus far have argued that decisions regarding pipeline design and gas composition should not preclude shipment of intermediate hydrocarbons such as butanes. (This position will be discussed in more detail later.) However, when the time comes to develop firm contingency plans for upset conditions, the State's interest in shipping intermediate hydrocarbons through the gas pipeline may well be surpassed by its likely --- and conflicting --- interest in maintaining high throughput levels: As the preceding discussion shows, in the event of upset, maintenance of throughput depends on an ability to reduce the suction pressure at the next compressor station, which in turn is partly limited by the proportion of intermediate hydrocarbons in the gas stream.

D. CARBON DIOXIDE CONTENT

Produced gas from the field (sometimes called raw gas) contains about 13 percent carbon dioxide (CO_2). Whether that amount is allowed to remain in the pipeline quality gas, or is removed via conditioning[3] down to a 1 percent or 3 percent level, depends on several factors:

---

3) Some parties with an interest in ANGTS have used the words "gas conditioning" and "gas processing" interchangeably; and in many Lower 48 producing areas, the boundary between the two stages of natural gas treatment is hard to define. With respect to Prudhoe Bay natural gas, these two phrases have distinct regulatory definitions, which may result in very real differences in the price the law allows gas producers to receive. As a result, the producers are easily aggrieved by any "misuse" of the two terms. We will make no attempt here at a rigorous distinction between gas processing and conditioning; the reader should simply be aware of the sensitivity of this matter.

1. The effect of carbon dioxide on hydrocarbon dewpoint. Figure D shows that a 13 percent CO_2 mixture enables the introduction of greater quantities of heavy hydrocarbons than would be safe with a 1 percent CO_2 mixture, but the effect is really rather small. Instead, the choice of CO_2 concentration must be made on other grounds.

2. The effect of carbon dioxide on pipeline corrosion. Under certain conditions, carbon dioxide will combine with water to form carbonic acid. If present in the sales gas stream, carbonic acid will corrode the steel walls of the pipeline. The question, then, is how various concentrations of CO_2 affect the risk that carbonic acid will seriously damage the pipeline during the twenty-plus years of gas shipments.

The producers collectively argue that carbonic acid corrosion in the Alaskan section of the gas pipeline is a false issue, in part, because it takes two to tango. Carbon dioxide in any concentration cannot turn into carbonic acid except in the presence of "free" water (water that condenses out of the vapor phase). Since enough water must be removed to meet WATER dewpoint specifications of -35 degrees F. for the section of pipeline in Alaska, no problem should ensue unless the temperature within the pipeline falls below that point; but the HYDROCARBON dewpoint specification will have to be much higher --- somewhere around 0 degrees F. in order to maximize shipment of intermediate hydrocarbons. Thus, before carbonic acid formation could pose a serious threat to the pipeline, hydrocarbons present in two-phase flow conditions would already have made the system inoperative.

Northwest Pipeline Company counters the producers' arguments with a different concern from its own standpoint as pipeline operator. While the sales gas containing more than 1 percent CO_2 may indeed ENTER the pipeline at Prudhoe Bay in a dehydrated condition that poses no threat of corrosion, the pipeline operator must ensure that the gas REMAINS corrosion-free throughout the several thousand miles of its journey. Apparently, some water is expected to contaminate the sales gas not only as a result of upset conditions, but even during hydro-testing associated with pipeline start-up. Whether Northwest's demand for a 1 percent CO_2 specification, therefore, is reasonable, has not yet been decided by FERC.

Because of permafrost problems in Alaska, the temperature of the gas must be held below the freezing point of water. Hence, if any water drops out in Alaska, it will likely do so in the form of ice or more precisely, hydrates, which are like ice crystals but encapsulate molecules of light hydrocarbons or sulphur compounds within their structures. At the planned operating temperatures for the Alaska pipeline segment, free water will form hydrates at temperatures as high as 60 degrees F. But ice and hydrates, unlike water, cannot combine with CO_2 to form an acid. Instead of gradual corrosion, the presence of solids will present a more immediate problem: blockage of the pipeline and its valves.

The Canadian section of the pipeline poses, perhaps, an even more fundamental concern. Canadian regulators have given preliminary approval to a water dewpoint specification for gas added to pipeline sections south of Whitehorse that is less stringent than specifications proposed for the

AGO 533008

Alaska section. This difference, however, does not indicate any malfeasance by Canadian pipeline owners and regulators, but rather a difference in judgment about what constitutes acceptable risks in the face of added costs for prevention.

3. The effect of carbon-dioxide on downstream gas systems. Purchasers of Prudhoe Bay gas have argued that a high CO_2 content would adversely affect their interests in several ways.

In its July 1979 comments to FERC, the Natural Gas Pipeline Company of America states that a gas of 13 percent CO_2 would create corrosion problems within its own pipeline system, because that system's low-CO_2 gas from other sources has a relatively high water content. In addition, if Alaska gas contained excessive amounts of CO_2, it would have to be mixed with large quantitites of gas from elsewhere in order to ensure consistent burning characteristics.

Northern Natural Gas Company in its letter to the Alaskan Gas Project Office of FERC (dated December 7, 1978), advocates even more stringent CO_2 standards. It claims that its purchased volumes of Alaska gas will first be stored as LNG and, as such, cannot tolerate a CO_2 content that exceeds about 200 parts per million (ppm). But as the State of Alaska observed in its reply comment of June 1979, all pipeline gas must undergo CO_2 removal at the LNG plant site. The State concluded, therefore, that Northern's concern should not influence the choice of CO_2 specifications for North Slope gas.

The valid point raised by Northern, however, was that most LNG facilities are now designed to treat pipeline gas whose CO_2 content does not exceed 1 percent. Hence, the additional expense that shippers must bear to treat 3 percent CO_2 gas must be taken into account in assessing the conditioning and transportation costs for Prudhoe Bay gas.

AGD 533009

4. The effect of carbon dioxide on project economics. One other area of concern has entered the debate on CO_2 specifications --- overall project economics. How would different CO_2 levels affect the cost of conditioning versus the cost of pipeline transportation?

The Ralph M. Parsons Company (in its February 1979 CO_2 specification study[4]) estimates that by relaxing the CO_2 removal process to yield a sales gas of 3 percent CO_2 instead of 1 percent, the conditioning plant construction costs could be pared down by about 7 percent. If no CO_2 removal facilities were built (yielding a sales gas of 13 percent CO_2), construction costs would be about half as much. Fuel requirements for the scaled-down conditioning plant would decrease by 8 percent in the 3 percent CO_2 case, and would drop by about one-third in the 13 percent case.

TABLE 5

COSTS OF CONDITIONING	1% CO_2 (base case)	3% CO_2	13% CO_2
Construction cost	100%	93%	54%
Fuel requirements	100%	92%	66%

4) The Ralph M. Parsons' studies of conditioning processes and facilities were financed jointly by the North Slope producers and a half dozen likely gas shippers (interstate gas transmission companies). It was conducted about two years ago and, necessarily, had to adopt some working assumptions in spite of the many unknowns. Consequently these assumptions and the study conclusions are not totally satsifactory to all of the sponsoring parties. The study is, however, the only in-depth analysis that presently exists; and it is, therefore, widely quoted.

Table 5 suggests that from the standpoint of conditioning costs and fuel requirements on the North Slope alone, the 13 percent CO_2 case is a clear winner. One must remember, however, that such high CO_2 levels would impose greater transportation costs, additional capital costs downstream (since CO_2 must be removed prior to customer distribution), and it threatens pipeline corrosion. The table also shows that a 3 percent CO_2 specification is preferable to one percent, but not overwhelmingly so.

On the other hand, Northwest Alaskan Pipeline Company in its February 1979 "CO_2 Transportation Study", shows that a 3 percent or 13 percent CO_2 specification would cost MORE than a 1 percent specification from the standpoint of pipeline transportation costs. (While the added volume of CO_2 contributes no additional heating value to the gas stream, it does require an increased investment in compression equipment and more fuel during pipeline operations.) But here too, the cost differences between the 1 and 3 percent CO_2 specifications are not very substantial.

In comparing how much money would be SAVED in the conditioning process by moving from a 1 percent CO_2 specification to 3 percent, versus how much additional money and fuel would be SPENT for pipeline transportation, even Northwest admits that the conditioning cost savings are of greater importance [p 5. of Northwest's "CO_2 Transportation Study"]. The difficulty for FERC will be in judging the significance of this net cost savings compared to the pipeline corrosion and downstream marketing problems previously discussed. FERC has, at least for the present, ruled that the cost of reducing CO_2 content below 3 percent, if required, is to be treated as a conditioning cost. Until the issue of conditioning cost allocation is finally decided, however, we cannot know whether it is the producers (and the State of Alaska) or the gas consumers who would benefit from an attempt to optimize total project costs.

E. VOLUMES OF GAS AND GAS LIQUIDS AVAILABLE FOR SHIPMENT

No intelligent discussion about sales gas composition can take place without some agreement as to what volumes and kinds of hydrocarbons will actually be AVAILABLE for shipment through the gas pipeline. Previous debate on the matter of gas composition has, in fact, been clouded by differing outlooks on gas availability. Worse yet, those discrepancies in underlying assumptions have largely been overlooked. Again, whether all the intermediate hydrocarbons will be ALLOWED to enter the gas pipeline for shipment is a complex question with which the rest of this report is concerned --- but that is all the more reason to make sure that hidden differences in assumptions about hydrocarbon availability are not ultimately responsible for disagreements on other matters.

This section will examine the three factors that determine how much and what kind of hydrocarbons are available for shipment through the gas pipeline: (1) reservoir production rates, (2) North Slope fuel requirements, and (3) the ability of the TAPS oil pipeline to carry intermediate hydrocarbons.

1. Reservoir production rates.

The field rules for the Prudhoe Bay reservoir currently limit raw gas production to 2.7 bcf per day, and it is expected that this rate can be maintained for 25 or more years. This rate, in turn, will yield about 2.0 bcf per day of conditioned gas. No one, of course, can guarantee that such offtake levels will indeed be physically possible, or that Alaska's Oil and Gas Conservation Commission will approve them throughout the life of the field, because

AGO 533012

the reservoir's production capabilities are based on predictions of FUTURE performance; but no one is now arguing seriously that any other figure makes more sense from the standpoint of today's planning needs.

2. Gas composition changes.

The expected hydrocarbon composition of that steady 2.7 bcf per day, however, IS expected to change through time. During the early years of gas sales, solution gas bubbling out of the crude oil will comprise the greater portion of total gas volume. But as crude oil production drops off, so will the volume of solution gas. The 2.7 bcf per day, instead, will increasingly consist of gas that comes directly out of the gas cap. Since gas cap gas is "leaner" in heavier hydrocarbons than the solution gas, the combined gas mixture, as well, will grow leaner through time.

ARCO [Dickinson letter to Tussing; January 3, 1980] estimates that by the 25th year of gas offtake, the natural gas liquids (NGL) content of the produced gas will have dropped by about 17 percent. Similarly, SOHIO [Pritchard letter to Barlow; January 23, 1980] estimates a drop-off in the ethane-propane NGL component of roughly 20 percent. The crucial issue is not, however, the absolute volumes of NGL's that must transit TAPS, but the PROPORTION of butanes in the oil stream, a ratio that promises to increase over time as oil production declines. It is nevertheless doubtful whether this trend is significant enough to merit any real consideration in system planning and design --- especially given the likelihood that during the 25 year operating period other gas reservoirs with different gas compositions will be tapped.

While the changing hydrocarbon content of PRUDHOE BAY natural gas may not be a major consideration in the design of ANGTS, system engineers do have to take into account the likelihood that gas produced from other, still undiscovered or undeveloped reservoirs on the North Slope may differ significantly in chemical composition. Prudhoe Bay gas is relatively sweet and wet (low in sulfur compounds and rich in NGL's), and has a relatively high CO_2 content. A conditioning plant designed to treat this raw gas stream, or a pipeline designed to carry it, would be uneconomic or even inoperable for gas from another reservoir which happened, for example, to be sour and dry, and contained little CO_2.

Under the present plan for ANGTS, the initial conditioning plant will be located on the North Slope and designed expressly to treat the volume and mixture of compounds the Prudhoe Bay reservoir is expected to produce. If new and different gas mixtures later came on stream from other reservoirs, the existing plant could be modified or new facilities added at the same place or elsewhere specifically to accommodate the new supply. In either case, the pipeline itself can be built to accommodate pipeline-quality (fully-conditioned) gas from any source in Arctic Alaska. If the conditioning plant were at Fairbanks or further downstream on the pipeline, however, system engineers would face the far more difficult task of designing both the pipeline and the conditioning plant to handle a stream of raw gas whose characteristics might change radically over time.

Thus, the possible need for ANGTS to handle different (and yet unknown) gas mixtures over its operating life is one reason why the gas producers, Northwest Alaskan, the prospective gas shippers, and FERC all seem to agree that the conditioning plant for Prudhoe Bay gas should be located on the North Slope, despite the belief of many Alaskans that construction and operating costs would be less, and local economic benefits greater, in an Interior Alaska location.

AGO 533014

3. North Slope fuel requirements.

It takes a good deal of energy to produce, clean and condition, and transport oil and gas from the North Slope. This energy must be drawn out of the stream of produced hydrocarbons. There are three general categories of North Slope fuel uses: (1) FIELD FUEL, (2) TAPS FUEL, and (3) PLANT FUEL (for the gas conditioning plant).

(1) FIELD FUEL is needed for all of the activities relating to oil and gas PRODUCTION. In addition to actual oil production at the wells, energy is consumed in gathering the oil into facilities where the crude can be separated from the solution gas, dehydrated of its water content, and cleaned of its impurities. Field fuel is also consumed by the Prudhoe Bay electric generating plant. Produced gas in excess of fuel requirements is currently compressed to about 4000 psi for reinjection into the reservoir, pending the onset of gas sales. This function is performed in the Central Compressor Plant, which, likewise, requires a a good deal of energy.

Estimates of future field fuel requirements, such as those used in the Ralph M. Parsons Company report, must also provide for additional production activities, which will include more elaborate facilities for injecting back into the reservoir the produced water that is separated from the crude, and for the injection of source water from the Beaufort Sea in order to maintain reservoir pressure. (This is sometimes called waterflooding.) The "maximum" field fuel case used in the Parsons report takes all of these activities into account.

(2) TAPS FUEL is that which is needed to run the first four pump stations of the Trans-Alaska oil pipeline. While pump stations south of Station #4 provide for their own fuel

AGO 533015

requirements by processing a portion of the crude oil into diesel fuel in individual topping plants, the TAPS owners decided that it would be cheaper to supply the more northerly pump stations with North Slope gas by means of a buried gas pipeline beside the oil line. Unlike the TAPS oil pipeline, the Alaska Highway gas pipeline will transport a mixture of hydrocarbons that can be used directly in its compressor stations, thus no provision has been made for supplying even its northern portions with a separate energy stream.

(3) PLANT FUEL is needed for all aspects of the gas conditioning process --- for (a) separating and fractionating propanes, butanes, and pentanes-plus from the lighter hydrocarbons; (b) for removing carbon dioxide from the remaining methane-ethane stream; and (c) for chilling and compressing the conditioned gas to meet the requirements for shipment through the gas pipeline. Sometimes PLANT FUEL is discussed more specifically as HEATER FUEL and TURBINE FUEL. The distinction is made because while heaters can run on a relatively low BTU fuel, turbines have more stringent requirements.

Where does all this fuel come from? Currently, the Field Fuel Gas Unit conditions a portion of the raw gas to provide energy for most ongoing field activities and for TAPS.[5] Since the TAPS fuel gas line experiences extremely cold temperatures enroute to the pump stations, the Field Fuel Gas Unit yields a gas stream with exceptionally stringent specifications --- a -40 degree F. hydrocarbon dewpoint and a -60 degree F. water dewpoint. When waterflooding begins, the Field Fuel Gas Unit can be expanded to

---

5) The gathering centers in the western part of the field furnish their own fuel.

accomodate the new demand. Or, as the Parsons study anticipates, additional FIELD FUEL requirements can be met by fuel generated at the conditioning plant. The Parsons study has chosen the latter technique in an attempt to optimize the entire system, disregarding ownership responsibilities. In so doing, an outlet is found for the ethane-rich CO_2 "waste" gas that is a by-product of the CO_2 removal process selected by Parsons. This stream is enriched with propane to provide a fuel suitable for field activities.[6]

Nevertheless, the producers make a point of emphasizing that they have several options for taking care of all their own fuel needs in the field and for TAPS, and they have not yet decided whether it would be in their interest to enter into an arrangement with the owner of the conditioning plant (whoever that may be) simply for the sake of overall project optimization. After all, their gas sales contracts commit for sale only the gas that is EXCESS to field and TAPS requirements. The producers further stress the potential disadvantages of making their crude oil production, processing, and transportation facilities dependent upon a stream of by-products from the gas conditioning plant. This concern would probably be even greater if the conditioning plant were operated and controlled by another party, such as the state.

Of course, the PLANT FUEL requirements will have to be met by the owners of the conditioning plant. Parsons Company, in its proposed plant design, has selected what it

---

6) No one knows exactly how much field and TAPS fuel will be needed in the future. Moreover, those requirments will vary almost daily. Parsons, therefore, calculated both a "maximum" and a "minimum" field fuel case. Most parties believe the "maximum" case data is the more relevant for planning.

considers to be the most economical CO_2 removal process, given the raw gas composition and the probable gas pipeline specifications. The process chosen by Parsons, however, results in a waste gas that also contains about half of the ethane that enters the plant.[7] Accordingly, Parsons recommends using the ethane-CO_2 by-product for fuel. Given the fact that SOMETHING has to be burned as fuel, this is not necessarily a bad thing --- unless there is some reason to view the ethane (and the propane that enriches it) as exceptionally valuable hydrocarbons for which a better use exists. There is little argument within Alaska that ethane would be the most desirable feedstock for a local petrochemical industry. It is still unclear, however, whether an ethane based petrochemical plant is economically feasible in Alaska, and even if it were, whether all of the ethane would, in fact, be required for such a facility. For example, the November 1979 study prepared by Bonner & Moore Associates for the State of Alaska indicates that only about one-fourth of the ethane is needed to feed a "world-scale" petrochemical plant, in which case, the CO_2 removal process chosen by Parsons Company in itself should cause no alarm.[8]

One other major point of controversy arises with respect to design of the CO_2 removal process and PLANT FUEL requirements. The ethane-rich CO_2 waste gas has a lower heating value (net BTU) of about 200 to 220 BTU per cubic foot. While this mixture may be adequate for use in

---

7) The Parsons design absorbs CO_2 via a physical, rather than a chemical, process. This process is much like fractionation in that the components are separated by their different boiling points. Given that the boiling point of ethane is relatively close to that of CO_2 (see Table 3), some of the ethane necessarily will "flash" off with the CO_2.

8) Bonner and Moore Associates, Inc., Promotion and development of the Petrochemical Industry in Alaska (November 1, 1979). See also the author's critical review of the Bonner and Moore report, "Prudhoe Bay Natural Gas Liquids, the Alaska Highway Gas Pipeline, and Petrochemical Development in Alaska" (January 20, 1980).

AGO 533018

the plant heaters, it must be enriched to meet the specifications of the local turbines and field equipment. The Parsons Company design raises the BTU content by propane "spiking" to achieve a net heating value of about 475 BTU/cf for local turbine fuel, and 825 BTU/cf to suit the design limitations of existing field equipment. The controversy lies in the fact that while propane can easily be shipped south in the gas pipeline, butanes are more troublesome. Therefore, wouldn't it make more sense to use butane rather than propane for spiking purposes?

Unfortunately, the answer is not so simple. Butane could create the same hazards in the fuel system that it poses in the Alaska Highway gas pipeline --- condensation at low temperatures. In addition, its burning characteristics are different from those of propane, because it packs a bigger wallop of combustible carbons in each molecule. While use of butane instead of propane is not entirely out of the question, those responsible for smooth operations on the North Slope naturally will look for system designs and fuel compositions that promote simplicity and reliability. Unless the State of Alaska can demonstrate a special interest in the propanes or butanes that differs markedly from that shared by the other gas owners, any second-guesses the State might make with respect to fuel enrichment decisions would probably be viewed by others as unduly meddlesome.

Table 6 provides a perspective on North Slope fuel consumption. Of the hydrocarbons in the raw gas stream, about 15 percent will be consumed as field fuel, by the TAPS pump stations, and during the conditioning process.

TABLE 6

NORTH SLOPE FUEL REQUIREMENTS[1]

	Produced[2] Gas	FFGU[3] Outlet	Conditioning Plant Inlet	Field[4] Fuel	Plant[5] Fuel	Available[6] Hydrocarbons
Billion BTU/day (gross)	2849	[95]	2754	[214]	[113]	2427
Million cf/day	2700	[100]	2603	[236]	[248]	2104
Average BTU/cf (gross)	1055	953	1058	906	456	1154

NOTES:

1. Source: Exxon, personal communication (February 1980). Exxon personnel calculated these data using the Parsons reports maximum field fuel case.

2. An offtake rate of 2.7 bcf/day is assumed, consistent with the Prudhoe Bay reservoir field rules set by the Alaska Oil and Gas Conservation Commission. Parsons assumed a 2.8 bcf/day offtake rate.

3. FFGU Outlet signifies the fuel products of the Field Fuel Gas Unit that are used in the northern pump stations of TAPS and for a variety of field activities. Heavier hydrocarbons removed during that process are routed (along with the rest of the produced gas) to the conditioning plant and its fractionators.

4. Field Fuel designates those North Slope energy requirements that exceed the output of the Field Fuel Gas Unit. The present capacity of the Field Fuel Gas Unit is 100 million cubic feet per day. Parsons assumes that this capacity will be utilized fully, but that additional field fuel needs will be met by products of the conditioning plant, rather than by an expansion of the FFGU.

5. Plant Fuel includes both turbine and heater fuel for the conditioning plant. 456 BTU per cubic foot, therefore, represents the weighted average of the heating values for the relatively high BTU turbine fuel, and the low BTU heater fuel.

6. Available Hydrocarbons are the final product streams available for shipment through the gas pipeline or blended into TAPS crude.

AGO 533020

4. Shipping intermediate hydrocarbons through TAPS.

As mentioned earlier, the Alaska Highway Gas pipeline will have no problem carrying light hydrocarbons (C_1, C_2, and C_3) in a vapor phase, while the TAPS oil pipeline can easily handle heavy hydrocarbons (C_6+) in a liquid phase. The question, then, is whether both systems together can support shipment of all of the intermediate hydrocarbons (C_4 and C_5) without encountering the hazards of two-phase flow.

Referring once again to Figure D, the reader will note that upset conditions attendant to a 1260 psig system limit the amount of butanes that can be transported through the Alaska Highway Gas Pipeline. The phase diagrams show that while 50 percent of the available butanes might be handled safely, shipping all of the available butanes would not be possible. Nobody can precisely judge what will constitute a safe limit, of course, until the pipeline engineering and contingency plans are completed. But it is clear that all of the pentanes and something less than half of the butanes will have to find another means of transport, such as TAPS.

Right now, crude oil enters the TAPS oil pipeline on the North Slope at 140 degrees F. Table 3 (on page 4) shows that at 140 degrees F., C_6 is a liquid but that C_5 and lighter hydrocarbons would be present in a vapor phase[9] What are the prospects for lowering the TAPS inlet temperature to enable it to accept all the pentanes and maybe even some of the butanes?

---

9) The table, however, makes no provision for the fact that hydrocarbon MIXTURES can safely accomodate some small volume of light hydrocarbons which, as pure substances, would exist as vapors.

Most parties agree that the inlet temperature of TAPS can not feasibly be reduced below about 110 to 112 degrees F. Three factors account for this limitation:

(1) Even if the inlet temperature were reduced, say, to 100 degrees F., the warm summer months combined with the heat naturally generated by the friction of flow would result in somewhat higher temperatures in certain parts of the pipeline. Thus the temperature threshold that limits the introduction of intermediate hydrocarbons into the crude cannot effectively be reduced beyond about 100 degrees [Pritchard letter to Barlow; January 23, 1980].

(2) On the other hand, if the TAPS inlet temperature is reduced, the heavy components of the crude oil ("waxes") will solidify more readily, slowing the flow and thereby reducing the daily throughput. At lower inlet temperatures, the line will have to be "pigged" more often to strip away the wax build-up. Moreover, if inlet temperature specifications were relaxed, TAPS would face a greater risk that wax solidification might cause real problems if the line experiences an extended shut-down during the winter cold.

(3) Even if both of the previous limitations were ignored, there are practical constraints on the amount of intermediate hydrocarbons that can be shipped through TAPS. In order to control air pollution in the Los Angeles basin, government regulations permit no landing of crude oil with vapor pressures higher than 11.1 psia at storage temperatures of, say, 100 degrees F. That is, crude must emit no vapors when subjected to pressures at or above 11.1 psia and to temperatures at or below 100 degrees. Since the lowest pressure at which TAPS operates is around the atmospheric pressure of 14.7 psia, rather than 11.1 psia, a TAPS bubble-point specification compatible with California's standard would have to be somewhat above 100 degrees.

Given all three constraints just discussed, most parties seem to believe that a reasonable minimum inlet temperature for TAPS is about 110 to 112 degrees F. At that temperature, both ARCO [Dickinson letter to Tussing; January 3, 1980] and the Ralph M. Parsons Company [September 1978 study report, Volume II, page 2-271] believe that essentially all of the available pentanes and butanes could be transported through TAPS, at peak crude oil throughput rates. SOHIO, however, suggests that only some of the butanes can be accomodated [Pritchard letter to Barlow; January 23, 1980].[10]

Nevertheless, assuming that the gas pipeline can safely handle at least 50 percent of the available butanes as previous discussed,[11] there appears to be little chance that butanes will be stranded on the North Slope --- at least in the early years of gas shipments. As oil production declines, however, the ability of TAPS to carry intermediate hydrocarbons will drop accordingly. This decline is expected to occur much faster than the offsetting feature of a progressively "leaner" raw gas stream mentioned earlier. For example, assuming (1) a 1985 start-up for the gas pipeline, (2) ARCO's oil production forecast [Dickinson letter to Tussing; January 3, 1980], and (3) the Parsons' phase diagrams [Volume II, pp. 2-287, 2-297, of the September 1978 conditioning study], all of the "available" pentanes and butanes could be shipped through TAPS initially, but the oil line could no longer accept ANY butanes by the seventh year of gas shipments.

---

10) Before one focuses on the apparent disagreement, it must be remembered that all calculations to date have been rough and possibly based on different crude oil assays, or different decline rates for crude oil production. Sohio is scheduled to complete a more refined analysis of this matter in early 1980.

11) Most parties agree that it is realistic to assume that ANGTS can accommodate about 85 percent of the butanes available after removal of the various fuel streams in the Parsons' maximum field fuel case. The State believes, however, that if NO ethane or propane is burned on the Slope, and those hydrocarbons are instead shipped through the gas pipeline, only about 25 percent of the butanes could be accommodated in ANGTS.

AGO 533023

Is there, then, any real cause for alarm? First, putting things in perspective, even in the early years of gas production when butane content is greatest, it will comprise less than 2 percent of the gaseous hydrocarbon volume (though about 5 percent of the total BTU content of the raw gas stream). Moreover, unless there is some reason to believe that the producers and their gas purchasers have less interest than the State in getting as many of the North Slope BTU's to market as possible, here too, it may be unreasonable for the State to make second-guesses on the best overall system design.

PLEASE NOTE: THE PRECEDING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

Ex 1129
File: Bonding Auth

LAW OFFICES OF
PRESTON, THORGRIMSON, ELLIS, HOLMAN & FLETCHER
420 L STREET
SUITE 404
ANCHORAGE, ALASKA 99501
AREA CODE 907-276-1969

FREDERICK H. BONESS
JOHN R. MESSENGER

2000 IBM BUILDING
SEATTLE, WASHINGTON 98101
206-623-7580
TELEX THOR-SEA

919 EIGHTEENTH STREET N.W.
SUITE 300
WASHINGTON, D. C. 20006
202-331-1005
TELECOPY 202-331-1024

September 21, 1979

The Honorable Thomas K. Williams
Commissioner
Alaska Department of Revenue

Re: Alaska Gas Pipeline Financing Authority

Dear Commissioner Williams:

At your request we have reviewed A.S. 44.55 (the "Act") establishing the Alaska Gas Pipeline Financing Authority (the "Authority") and certain amendments to the Act which have been suggested. Our review has centered on those provisions of the Act which relate to the approval of the financial and Alaska impact plan (the "Plan") and the authorization, approval and issuance of bonds. We have not commented on the contents of the Plan itself since these appear to relate to policy matters which (although they may affect the practicality of the issuance of bonds) do not directly affect the legal ability of the Authority to issue bonds. This letter and the attached memorandum (Attachment A) contain our initial analysis of the legislation.

In the brief time available we have not been able to prepare definitive language for some technical changes which we suggest relating to the purposes and provisions of bonds which may be issued. As to most matters discussed, however, we have drafted amendments which reflect our comments (See Attachment B - Draft Revisions).

We have approached this analysis for the standpoint of bond counsel, and accordingly, our recommendations may seem overly cautious. By this, we mean that in analyzing a particular problem we may recommend a legislative amendment even though we might conclude that the Authority would ultimately prevail in any legal

challenge on the matter. We have approached our analysis in this manner so that, to the extent possible, the Authority may avoid litigation on its issuance of bonds and that it may be able to obtain an unqualified approving legal opinion on such bonds. It is much easier to make clarifying changes at this point than to later resolve questions which might otherwise arise.

This letter addresses the following subjects:

A. Purposes and Security for Bonds of the Authority.

B. Approval Process for the Plan and Bonds.

1. General

2. Refunding Bonds

3. Amendment of the Plan

4. Approval of the Plan

C. Lending of Credit.

D. Compliance with "on behalf of" Regulations.

E. Public Purpose.

F. Other Suggested Changes.

1. "Project Sponsor"

2. "Notes"

3. Interim Financing

4. Pledge to Bondholders

5. Other

The attached Supplemental Memorandum provides additional explanation of some of the matters summarized in this letter and discusses other matters which we have concluded do not require amendments to the Act.

A. Purposes and Security for Bonds of Authority

The Act, in its present form, does not clearly state the purposes for which bonds of the Authority may be issued. Section

44.55.090(a) presently authorizes the issuance of bonds only "for the purpose of purchasing or otherwise acquiring any obligation issued with respect to the project . . . and for the establishment of reserves to secure or pay bonds. . . ." We suggest that the existing provisions in § 44.55.090(a) be amplified to clarify and broaden the purposes for which bonds may be issued. See attached draft revisions § 44.55.090(a).

The manner in which an Authority financing is to be accomplished - the security arrangements and permissible covenants upon which an issue of bonds is based - is now stated in the Act in a sketchy manner. We understand that it is not known at this time what form the financing plan would take. Accordingly, it seems desirable to give the Authority powers which allow it to employ a wide range of financing techniques, in order that the ultimate selection of a financing plan (which the Legislature would pass on) will not be limited by lack of statutory authority. To this end, we recommend that the Act be revised to include the following: (1) a broad definition of project costs which may be financed; (2) clarification that interim and other financing of the project by the project's sponsor may be refinanced; (3) more detailed authority for the acquisition of property interests and the granting of security interests in such property; (4) authority for making loans to project sponsors, or other persons, in furtherance of the financing of the project; and (5) expanded powers to enter into trust arrangements.

Such provisions must be carefully drawn after a more detailed investigation into the background of the proposed financing than has been possible for us to accomplish in the time available to date. Accordingly, although we have begun work on such provisions, we would suggest that we be allowed a further period of time in which to prepare such provisions for consideration by the Authority.

B. Approval Process for the Plan and Bonds

1. General: The financial and Alaska Impact Plan required by A.S. 44.55.100 is in many respects an estimate or projection, rather than a set of legal restrictions. For example, two items which the Plan must contain are "projected debt service requirements of the bonds" and "the preliminary financing plan for the entire transmission system, as prepared for submission to the Federal Energy Regulatory Commission".

The language of A.S. 44.55.110, requiring that "no bonds or notes may be issued except in accordance with the approved plan", converts such estimates into legal limitations on the issuance of bonds. Converting estimates into limitations has major drawbacks.

First, some elements of the Plan are not suited to function as limitations. While it is desirable to have an estimate or projection of debt service, for example, almost all states have concluded that putting legal limitations on interest rates, which are governed by market forces, is unwise. Even if it were desirable to put a limitation on debt service, there should be some leeway between the estimate and the limitation. Second, some elements of the Plan are inherently preliminary and subject to change: for example, the "preliminary financial plan for the entire transmission system". If there is a deviation from this preliminary financial plan in some element not related to the issuance of the bonds, is the power to issue bonds impaired, because their issuance would not be "in accordance with the Plan"?

For the foregoing reasons we recommend the following revisions to the existing legislation: (1) provide that approval of the Plan and approval of bonds be contained in separate concurrent resolutions; (2) provide that approval of the bonds may contain such limitations as the legislature deems appropriate; (3) eliminate the requirement that bonds be issued and sold "in accordance with the Plan". See attached draft revisions - § 44.55.090(a) and 44.55.110.

2. Refunding Bonds: Refunding bonds are simply a type of Authority bonds. The approval process can be the same as for initial funding bonds, i.e., legislative approval by concurrent resolution. Revising A.S. 44.55.090(g) accordingly would permit elimination of confusing existing references to refunding bonds in A.S. 44.55.110, the approval section for the Plan.

We therefore recommend: (1) revising A.S. 44.55.090(g) (dealing with refunding bonds) to incorporate by reference the approval procedure for initial funding bonds; (2) eliminating references to approval of refunding bonds in A.S. 44.55.110. See attached draft revisions - § 44.55.090(g) and 44.55.110.

3. Amendment of Plan: The existing A.S. 44.55.110 implies that no amendments to the Plan may be approved after passage by the Authority of a resolution authorizing sale of the bonds. Such a restriction seems unwise, for two reasons. First, many potential changes in the Plan might be desirable, yet have no impact at all on the issuance of Authority bonds or the rights or interest of bondholders. Such changes should not be precluded. Second, this legislation cannot limit the right of a future legislature to make legislative changes. The only limitation on the actions of future legislatures which is triggered by the

issuance of bonds is the constitutional prohibition against impairment of contracts. An existing section of the legislation already addresses this concern (A.S. 44.55.140-"Pledge of the State.")

For the foregoing reasons, we therefore recommend that amendments to the Plan be permitted except to the extent prohibited by the "pledge" section, i.e., except to the extent amendments to the Plan would impair the rights of bondholders. See attached draft revisions - § 44.55.110.

4. Approval of the Plan: If the foregoing revisions are made A.S. 44.55.110, dealing with approval of the Plan, need only provide for approval of the Plan (or a conditional Plan) by concurrent resolution. The provision for disapproval by either house seems unnecessary, since both houses must approve the Plan before it can become effective. See attached draft revisions - § 44.55.110.

C. Lending of Credit

A.S. 37.10.085 prohibits the state from lending its credit or borrowing money for the use of a corporation. It is critically important to make clear that this statute does not apply to the Authority or its bonds. Our analysis of A.S. 37.10.085 is more fully set forth in the attached Supplemental Memorandum under "Lending of Credit." We strongly recommend addition to the Act of language excluding A.S. 37.10.085 from application to the Authority. See attached draft revisions - § 44.55.135.

D. Compliance with "on behalf of" Regulations

Under existing regulations of the Internal Revenue Service, it is probable that bonds issued by the Authority would not be regarded as being issued by the state or a political subdivision. Bonds of the Authority may nevertheless be tax-exempt if the Authority is held to be an entity acting "on behalf of" the state. See the attached Supplemental Memorandum for a more detailed analysis of this subject under The Authority as a "Constituted Authority". IRS regulations (§ 1.103-1) which are currently proposed, though not yet in effect, detail certain requirements which must be met in legislation such as the Act if the Authority is to be held to be issuing bonds "on behalf of" the state. Although these regulations could be changed at any time, it is desirable that the Act meet the requirements as they are now proposed. Accordingly, the addition of certain language to the Act relating to disposition of the earnings or property of the Authority is suggested. See attached draft revisions § 44.55.145 and 44.55.155.

E. Public Purpose

The state constitution (Art. IX, §6) prohibits the use of public money, property or credit except for a public purpose. It is thus essential that there be as little room as possible to question the public purpose for the proposed use of the proceeds of Authority borrowing to finance the project. The courts will usually give great weight to legislative findings of public purpose, but the existing legislative findings on which the Act is based are equivocal. It is important that they be changed to find that state financing of the project will, rather than may, promote an essential public purpose. A detailed examination of this issue is contained in the attached Supplemental Memorandum under "Public Purpose".

F. Other Suggested Changes

1. "Project Sponsor": Section 44.55.200(5) defines a "project sponsor" as "any partner of the Alaska Northwest Natural Gas Transportation Company, or its successors," thereby apparently excluding that company or its successors from the definition of "project sponsor." This seems to be an unintended result and the following language is suggested.

> "(5) 'Project sponsor' means the Alaska Northwest Natural Gas Transportation Company, or its partners or successors, or any other company, individual or association which owns an interest in the project or any part thereof."

2. "Notes": The Act sometime refers to "bonds" and, on other occasions, to "bonds or notes". This makes it uncertain as to whether or not the provisions of the Act which refer only to bonds relate to notes as well. Since the word "bonds" is defined to include notes (A.S. 44.55.200(5)), reference to notes in the body of the legislation should be excluded.

3. Interim Financing: It may be desirable to issue obligations for interim financing pending the issuance of bonds. We suggest that language be added to the definition of "bonds" (A.S. 44.55.200(2)) to make it clear that interim financing may be authorized by the Legislature as well as permanent financing. See attached draft revisions - A.S. 44.55.200(2).

4. Pledge to Bondholders: The "Pledge" section appears to adequately protect bondholders interests, except in two respects. First, the pledge in Section 44.55.140 should be a direct pledge to the holders of the bonds, not a pledge to agree with the holders of the bonds. It is not clear whether the mechanism

provided for such a later agreement by the Authority with the bondholders binds the State. Second, very large amounts of bonds are commonly issued in several series, only as funds are required and to permit the market to absorb the bonds over a period of time. In such cases, it is necessary to assure the purchasers of the initial series that there is no obstacle to the issuance of the subsequent series, so that financing can be completed. The "pledge" section should be amended to include a promise that power to issue bonds will not be withdrawn once an initial series has been sold. See attached draft revision - § 44.55.140.

5. Other: Various other minor textual changes are suggested in the attached draft revisions. Also, we suggest the language in A.S. 44.55.090(a) referring to § 103 of the Internal Revenue Code be deleted, as the code may change in such a way that the bonds would not literally meet this requirement.

SUMMARY AND CONCLUSION

In summary we recommend as follows:

1. Modification of A.S. 44.55.090 to clarify the purposes for which bonds may be issued, and to provide that bonds may be issued only after approval of the financial and Alaska Impact Plan and pursuant to a separate resolution specifically approving the bonds.

2. Additions to the Act to better assure that the Authority will have the statutory authority to issue and secure bonds in such manner and for such purposes as may be proposed to and approved by the Legislature.

3. Modification of A.S. 44.55.110 to clarify the plan approval process.

4. Modification of the legislative findings to support the conclusion that financing by the Authority is for a public purpose.

5. Other changes to clarify and correct various sections of the Act as set forth in the attached draft revisions.

We would appreciate the views of the Authority as to these suggested revisions. The next step would be to place the suggested

amendments into formal bill format, which we would be happy to do at your request.

Very truly yours,

PRESTON, THORGRIMSON,
ELLIS, HOLMAN & FLETCHER

By: John R. Messenger By: David L. Beller By: Forrest W. Walls

ATTACHMENT A

Supplemental Memorandum

Alaska Gas Pipeline Financing Authority Legislation

LENDING OF CREDIT

A question might be raised as to whether the issuance of revenue bonds pursuant to the Act would conflict with the provisions of A.S. 37.10.085 relating to financial aid to corporations by the State or political subdivision of the State. A.S. 37.10.085 reads as follows:

> Sec. 37.10.085 FINANCIAL AID TO CORPORATIONS BY STATE OR POLITICAL SUBDIVISION.
>
> Neither the state nor a political subdivision of the state may
>
> (1) make a subscription to the capital stock of a corporation;
>
> (2) lend its credit for the use of a corporation; or
>
> (3) borrow money for the use of a corporation

Under this section, it could be argued that through the issuance of revenue bonds by the Authority for purposes of financing the Alaska Natural Gas Transportation System, the State or a political subdivision of the State would, in effect, be lending its credit or borrowing money for the use of a corporation.

In response it could first be argued that neither the State nor a political subdivision of the State is lending its credit or borrowing money when the Authority issues its bonds pursuant to the Act.[1/] This argument would be based upon the characterization of the Authority's bonds and the restriction on their issuance in AS 44.55.090(b)

1/ It might also be argued that the project sponsor Alaska Northwest Natural Gas Transportation Company, is not a corporation but a partnership and therefore any lending of credit would not offend A.S. 37.10.085. We doubt that this argument would ultimately prevail since the partners themselves are corporations and any benefit provided by the financing would flow to such partners.

That subsection reads:

> (b) The bonds issued by the authority do not constitute an indebtedness or other liability of the state or of a political subdivision of the state, but are payable solely from the income and receipts or other money of the authority. The authority may not pledge the faith or credit of the state or of a political subdivision of the state to the payment of a bond, and the issuance of a bond by the authority may not directly or indirectly or contingently obligate the state or a political subdivision of the state in any manner, except as specifically provided in this chapter.

This subsection specifically provides that bonds issued by the Authority are not obligations of the State or a political subdivision of the State. In addition, this subsection prohibits the authority from pledging the credit of or obligating in any manner, the State or a political subdivision of the State. As such, because of the status of the Authority's bonds and the restrictions on their issuance, there is no way that the authority through issuing bonds could be lending the credit of the State or a political subdivision of the State.

Secondly, it could be argued that notwithstanding the question of whether the issuance of the Authority's bonds is lending the credit of or borrowing money by the State, such lending or borrowing would not be prohibited by AS 37.10.085 since the issuance of bonds serves a public purpose.

In Wright v. City of Palmer, 468 P.2d 326 (Alaska 1970) the court held that because "significant control and restrictions" were retained by a city over a private corporation, city bonds to finance property leased to the corporation did not violate AS 37.10.085. In that case, the City of Palmer proposed to issue $450,000 in general obligation bonds for the purpose of financing a 20 year improvement program providing for the purchase of a site and the construction of a manufacturing and processing facility within the City of Palmer. After the general obligation bonds were issued, the City entered into an agreement with Huskey Manufacturing Corporation, a manufacturer of low-cost housing, whereby the corporation agreed: to lease the building which was to be constructed for a period of 20 years; keep its raw materials within the City for tax purposes; employ not less than 80% of its workers from the Palmer area; provide training facilities for its employees; maintain on-the-job training programs under state and federal auspices; use the public utilities owned by the City as much as possible; and make available a paved parking lot adjacent to the building for public uses.

It was argued that the bond issue and the improvement program violated AS 37.10.085 in that the City of Palmer was lending its credit or borrowing money for the use of a private corporation when it leased the facility, financed by general obligation bonds, to Huskey Manufacturing Corporation for its business operations.

The court found otherwise, holding that the significant restrictions and controls by City of Palmer insured a public purpose, thereby preventing a violation of AS 37.10.085. The court, in effect, let the determination of whether the lending of credit or the borrowing of money was for the use of a private corporation, turn on the question of whether there was a public purpose.

In the course of the opinion the court in Wright stated:

> Since significant restrictions and controls are retained by the City of Palmer over Huskey Manufacturing Corporation's operations, the bond issue in question is not violative of AS 37.10.085. These controls and restrictions were imposed upon the corporation to insure the effectuation of the public purpose objective of this bond issue. We think that the question of whether the public credit is being pledged for a private purpose is also comprehended under the broader question of whether a public purpose is served by the bond issue and plan for its expenditure, which is discussed below. (468 P.2d at 329)

Thus, Wright stands for the proposition that a lending of credit or a borrowing of money for the use of a private corporation does not exist when the State or a political subdivision of the State establishes significant restrictions and controls in the financing program to insure a public purpose and there is, in fact, a public purpose. This authority is pertinent in our situation since the legislature here, as did the City of Palmer in Wright, established significant restrictions and controls to insure a public purpose. We discussed above the public purpose set out in the Act.

Thus, it could be concluded that any lending of credit or borrowing of money would not be "for the use of a private corporation" within the meaning of AS 37.10.085 since a public purpose is present and insured by specific controls.

Therefore, because of the nature of the Authority, the restrictions of A.S. 44.55.090, other controls to establish a public purpose and in light of our later discussion of the public purpose concept, a court might hold that the issuance of revenue bonds under A.S. 44.55 for the Alaska Natural Gas Transportation System would not be a violation of A.S. 37.10.085. Specific legislation should, however, be enacted to avoid any question.

Accordingly, we propose the following amendment to the Act:

Sec. 44.55.135 OPERATION OF AS 37.10.085 EXCEPTED.

The authority shall not be considered to be the state or a political subdivision of the state for the purposes of AS 37.10.085.2/

THE AUTHORITY AS A "CONSTITUTED AUTHORITY"

It is, of course, appropriate to insure to the extent possible, that the Act is structured in such a way that if bonds are issued by the Authority they will be considered tax exempt under Section 103 of the Internal Revenue Code as obligations issued by a state or political subdivision of the state.3/

Sec. 103(a) of the Internal Revenue Code provides:

"§103 INTEREST ON CERTAIN GOVERNMENT OBLIGATIONS

(a) General rule. Gross income does not include interest on

(1) The obligations of a State, a Territory, or a possession of the United States, or any political subdivision of any of the foregoing, or of the District of Columbia; . . . ."

2/ Similar amendments of this kind can be found in other Alaska authority statutes. See A.S. 44.61.190 and A.S. 18.26.250.

3/ The main obstacle to tax exempt status of Authority bonds requires an amendment to Sec. 103(c) of the Internal Revenue Code relating to Industrial Development Bond restrictions (the "two county rule") and cannot be cured by amendments to the Authority Statutes.

Although Section 103(a) expressly provides that interest on obligations of a state, a territory, a possession, or a political subdivision thereof are exempt from tax, Treas. Reg. §1.103-1 and Rev. Ruls. 54-106, 57-187 and 63-20 have construed the language of Section 103(a) as also including obligations issued "on behalf of" a state or political subdivision of a state.

Since the Authority is probably not "the State" or a political subdivision of the State, as defined by the Internal Revenue Service (IRS) (because it does not have the requisite sovereign powers), its obligations will be tax exempt only if it meets certain conditions imposed by the IRS.

Until recently, those conditions were set forth solely in Treas. Reg. §1.103-1 and amplified in Rev. Rul. 57-187, 1957-1 C.B. 65, Rev. Rul. 60-248, 1960-2 C.B. 35; and Rev. Rul. 63-20, 1963-1 C.B. 24.

However, on February 2, 1976, the IRS published Proposed Regulation §1.103-1 (41 Fed. Reg. 4829-4831) which set forth new criteria for determining whether a particular obligation would be considered issued on behalf of a state or political subdivision of a state. This proposed regulation by its own terms would amend the existing Treas. Reg. §1.103-1 and would supercede all outstanding revenue rulings such as those mentioned above.

This proposed regulation applies to obligations issued on or after 180 days after final adoption or at the option of a state or political subdivision to obligations issued on or after February 2, 1976. Although this proposed regulation is not final, could be changed at any time, and applies only at the option of the state, it is probably prudent to follow it rather than relying on the existing regulation and revenue rulings since the proposed regulation may become final at any time, and it represents the most current public expression of IRS policy.

A major consideration under the proposed regulation is whether the issuer is a "constituted authority" empowered to issue obligations "on behalf of" the state or a political subdivision of the state. The proposed regulation sets out six requirements (§1.103-1(c)) for determining whether the actual issuer is a constituted authority. In simplified summary form these six requirements are:

1. The authority is specifically authorized pursuant to state law to issue obligations to accomplish a public purpose of the unit (state or political subdivision of the state). (§1.103-1(c)(2)(i))

2. The unit controls the governing board of the authority. (§1.103-1(c)(2)(ii))

3. The unit has either organizational control over the authority or supervisory control over the activities of the authority. (§1.103-1(c)(2)(iii))

4. Any net earnings of the authority (beyond that necessary for retirement of the indebtedness or to implement the public purpose of the unit) may not inure to the benefit of any person other than the unit. (§1.103-1(c)(2)(iv))

5. Upon dissolution of the authority, title to all property owned by the authority will vest in the unit. (§1.103-1(c)(2)(v))

6. The authority must be created and operated solely to accomplish the public purpose of the unit specified in the authority's statutory authorization. (§1.103-1(c)(2)(vi))

Although this list is a very simplified expression of the complex requirements set out in the proposed regulation, it nonetheless illustrates for purposes of discussion the criteria which will be used to judge whether the authority is a "constituted authority" empowered to issue obligations "on behalf of" the state.

With this criteria in mind, we have reviewed the Act including its provisions relating to membership, powers and purposes to determine whether the Authority would, in fact, qualify as a constituted authority under the proposed regulation. It is our view that the Authority meets the six requirements of Prop. Reg. §1.103-1(c) through either express provisions of the Act or through necessary implication under the Act. However, we believe that some amendments would be appropriate so that the six requirements would be met by express language in the Act to avoid any possible question that might arise.

To expressly meet requirement number 4 (§1.103-1(c)(2)(iv)), we suggest the following amending language:

SEC. 44.55.145 EARNINGS OF THE AUTHORITY.

The earnings of the authority in excess of the amount required for the retirement of indebtedness or the accomplishment of the purposes stated in this chapter may not inure to the benefit of any person other than the State.

To expressly meet requirement number 5 (§1.103-1(c)(2)(v)), we suggest addition of the following new section:

SEC. 44.55.155 DISPOSITION OF AUTHORITY PROPERTY UPON DISSOLUTION

Upon dissolution of the authority, title to all property owned by the authority will vest in the state.

In order to avoid any misunderstanding as to our views, we would like to emphasize two important limitations. First, our view as to whether the Authority is a constituted authority empowered to issue obligations of the state is based upon current interpretations of Section 103(a) by the Internal Revenue Service. Before the time that any bonds, if any, are issued by the Authority, these interpretations may change through the final adoption of regulations different from those now set out as Proposed Regulations §1.103-1 (41 Fed. Reg. 4829-4831).

Secondly, our views above should not be construed as a conclusion that obligations issued by the Authority pursuant to the Act would now be tax exempt obligations since even though such obligations would be issued by a constituted authority, those obligations must still meet the requirements relating to industrial development bonds under Section 103(b) of the Internal Revenue Code. As mentioned above, this issue requires specific Congressional action.

CONSTITUTIONAL ISSUES

We have reviewed the Act to determine what constitutional challenges might be raised against the Act including challenges that have been made to other state bonding authorities and municipal bonding programs. With one exception, we do not find any serious constitutional questions arising under the Alaska Constitution.

Independent Agency

For example, we do not believe that a serious question could be raised under Article III, §22 of the Alaska Constitution which prohibits the creation of an independent agency not within a principal department. We have reviewed the membership of the Authority, its placement within the Department of Revenue and the administration controls imposed under the Act and believe that it is sufficiently close to the facts and tests enunciated in DeArmond v. Alaska State Development Corporation, 376 P.2d 717 (Alaska 1962) and Walker v. Alaska

State Mortgage Association, 416 P.2d 245 (Alaska 1966) to insure that the Act does not violate Article III, §22 of the Alaska Constitution.

Restriction on State Debt

Similarly, we do not think that the Act or the intended activities of the Authority would run afoul of Article IX, §8 and §9 of the Alaska Constitution which place specific restrictions (including an election requirement) on contracting debt by the State or a political subdivision of the State. Among other reasons, Article IX, §11 sufficiently insulates the Authority's issuance of revenue bonds from an attack under Article IX, §8 and 9. Specifically, Article IX, §11 provides:

> SEC. 11 EXCEPTIONS
>
> The restrictions on contracting debt do not apply to debt incurred through the issuance of revenue bonds by a public enterprise or public corporation of the State or a political subdivision, when the only security is the revenues of the enterprise or corporation.

Because of the restrictions of A.S. 44.55.090(b), we believe that the Article IX, §11 exceptions would apply to the Act, and the issuance of obligations by the Authority under the Act, thereby preventing a violation of Article IX, §8 and 9.

Public Purpose

Given the existing language of the Act, a constitutional question could be raised under Article IX, §6 of the Alaska Constitution which provides:

> SEC. 6 PUBLIC PURPOSE.
>
> No tax shall be levied, or appropriation of public money made, or public property transferred, nor shall the public credit be used, except for a public purpose.

An argument could be made that the issuance of bonds by the Authority would constitute a use of the public credit, and that such use for financing the Alaska Natural Gas Transportation System would not be a public purpose. Additionally, the same argument could be made with respect to any legislative appropriation or transfer of state property to the Authority if such appropriation or transfer were, in fact, made or contemplated.

In response to such a challenge, an argument could be made that the public credit is not being used since under A.S. 44.55.090 the bonds issued by the Authority are not an indebtedness of the State or a political subdivision of the State. Further, under A.S. 44.55.090, the Authority is prohibited from pledging the credit or obligating in any manner the State or a political subdivision of the State. Specifically, A.S. 44.55.090(b) provides:

> The bonds issued by the authority do not constitute an indebtedness or other liability of the state or of a political subdivision of the state, but are payable solely from the income and receipts or other money of the authority. The authority may not pledge the faith or credit of the state or of a political subdivision of the state to the payment of a bond, and the issuance of a bond by the authority may not directly or indirectly or contingently obligate the state or a political subdivision of the state in any manner, except as specifically provided in this chapter.

This argument would be supported by the decision in DeArmond v. Alaska State Development Corporation, 376 P.2d 717 (Alaska 1962). This case involved the Alaska State Development Corporation, which was an instrumentality established to develop, stimulate and advance the business prosperity and economic welfare of Alaksa and its citizens. The corporation was authorized to issue bonds for its stated purpose but the Act provided that the corporation could not pledge the credit or the taxing power of the state or its political subdivisions and that the state and its political subdivisions were not liable for the debts of the corporation.

Although the court in DeArmond found a public purpose, under the meaning of Article IX, §6, it also found that the issuance of the corporation's obligations did not amount to a use of the public credit because the statute prohibited the corporation from pledging the credit and taxing power of the state and provided that the corporation's obligations were backed only by the resources and credit of the corporation. In particular, the court stated:

> Class A and B negotiable certificates are to be sold to the public in order to accumulate funds with which to make development loans. These certificates are backed only by the resources and credit of the corporation. The act specifically prohibits the corporation from pledging the credit or the taxing power of the state. The form of revenue bond adopted by the board of directors of the corporation provides therein:

'This bond shall not be deemed to constitute a debt of the State of Alaska or a pledge of the faith and credit of the State of Alaska, but shall be payable solely from the special fund provided therefor from revenues of the Corporation. The issuance of this bond shall not directly or indirectly or contingently obligate the State of Alaska to levy or to pledge any form of taxation whatever therefor.'

No public funds are being transferred to the corporation other than the loans just mentioned. The funds realized from the sale of certificates will come from private sources. The credit of the state is not being pledged. Even though we have found that the corporation's activities will serve a public purpose, it is clear enough that its objectives must be accomplished without the use of public funds and state credit. No violation of the constitution has been shown. (376 P.2d at 722)

Thus, it could be argued, based upon the language in A.S. 44.55.090(b) and the finding in DeArmond, supra, that the issuance of bonds by the Authority would not be a use of the public credit in violation of Article IX, §6 of the Alaska Constitution.

Despite the availability of this argument, it is important to buttress by the Act the existence of a public purpose.

The legislature created the Authority in A.S. 44.55.010, which provides:

SEC. 44.55.010 CREATION OF AUTHORITY

There is created the Alaska Gas Pipeline Financing Authority. The authority is a public corporation of the state. It is an instrumentality of the state within the Department of Revenue, but has a legal existence independent of and separate from the state. Exercise by the authority of the powers conferred by this chapter is an essential governmental function of tne state. (Emphasis added)

Upon the creation of the Authority, the legislature set out its findings relating to the passage of the Act in §1 ch. 90, SLA 1978. Among other findings of benefits to the State, the legislature found that the creation of the Authority served a public purpose. Those pertinent provisions are as follows:

Section 1. LEGISLATIVE FINDINGS. The legislature finds that

(1) if the state makes a final determination that production of natural gas from the Prudhoe Bay reservoir will be consistent with optimal recovery of oil and gas from the reservoir, and if the Congress of the United States and federal regulatory agencies take favorable action with respect to matters of Alaska natural gas policy, then timely construction of the Alaska Highway Natural Gas Pipeline Project will be in the best interest of the state and of the United States;

(2) state assistance to the financing of the project will promote an essential public purpose in assuring timely transportation to market of Prudhoe Bay natural gas;

(3) the project is essential to the development of the natural resources and the long-term economic growth of the state, and will directly and indirectly provide employment in the state;

(4) additional benefits to Alaska from the project include increased state and local tax revenues, enhanced availability of natural gas for Alaska communities, and stimulus and expansion of the private sector economy, including greater potential for development of in-state manufacturing, refining and processing facilities;

(5) construction of the project is a matter of statewide concern; there is no existing general law adequate for the purpose of assisting with financing of the project, as provided in this chapter;

(6) it is a public purpose of the State of Alaska to promote timely completion of the project through the creation of an instrumentality empowered to sell revenue bonds, the interest on which is exempt from federal income tax except when held by a substantial user or related person as these terms are defined in sec. 103 of the Internal Revenue Code of 1954 as amended, and to use the proceeds to purchase or otherwise acquire obligations issued with respect to the project.

. . . .

Thus, the legislature specifically found a public purpose in creating the Authority empowered to issue revenue bonds for financing the Alaska Natural Gas Transportation System. This public purpose was based upon its findings of state benefits

and interests such as increased employment, additional revenues, general economic development, development of new business and industry and meeting energy needs.

Such purposes as increased economic development, additional employment, and encouraging development of new business and industry have been found, in previous cases, as constituting valid public purposes within the meaning of Article IX, §6 of the Alaska Constitution. Alaska State Development Corporation, 376 P.2d 717 (Alaska 1962), Walker v. Alaska State Mortgage Association, 416 P.2d 245 (Alaska 1966); Wright v. City of Palmer, 468 P.2d 326 (Alaska 1970).

The principles involved in a determination of whether a public purpose is present were set out in DeArmond, supra:

> At the outset we observe that the phrase 'public purpose' represents a concept which is not capable of precise definition. We believe that it would be a disservice to future generations for this court to attempt to define it. It is a concept which will change as changing conditions create changing public needs. Whether a public purpose is being served must be decided as each case arises and in light of the particular facts and circumstances of each case.
>
> In determining the question presented this court adopts for its guidance the general rule, supported by the great weight of authority, that where the legislature has found that a public purpose will be served by the expenditure or transfer of public funds or the use of the public credit, this court will not set aside the finding of the legislature unless it clearly appears that such finding is arbitrary and without any reasonable basis in fact. (376 P.2d at 721).

In the context of the Authority the legislature has specifically found a public purpose and this stated purpose has been found in other cases to be a valid public purpose. Additionally, such stated purpose should be controlling and will not be set aside unless it can clearly be shown that such finding is arbitrary and without any reasonable basis in fact.

Since the original Act was passed, however, the legislature has amended its findings to negate or to at least call into question its finding of a public purpose. §4, ch. 31, SLA 1949 amended section 1(2) ch. 90 SLA 1978 as follows:

(2) state assistance to the financing of the project may [WILL] promote an essential public purpose in assuring timely transportation to market of Prudhoe Bay natural gas. . . ."

In addition, like findings (financing the project may promote a public purpose) were made in Legislative Resolve No. 13 in 1979.

The legislature did not, however, amend its finding of public purpose in Section 1(6), ch. 90 SLA 1978 which reads as rollows:

(6) it is a public purpose of the State of Alaska to promote timely completion of the project through the creation of an instrumentality empowered to sell revenue bonds, the interest on which is exempt from federal income tax except when held by a substantial user or related person as these terms are defined in sec. 103 of the Internal Revenue Code of 1954 as amended, and to use the proceeds to purchase or otherwise acquire obligations issued with respect to the project;

Because of the legislative change of the word "will" (promote a public purpose) to "may" in section 1(2) and its conflict with the language in section 1(6) of ch. 90, SLA 1978, as well as like findings in Legislative Resolve No. 13, we think that the legislature may have neutralized the legal presumption which it previously had established. That being the case, a court might determine the question of a public purpose without such presumption.

In light of this uncertainty and lack of legislative presumption on the question of public purpose, litigation might well have to be instituted to establish the Act's public purpose before any bonds could be issued.

To avoid this uncertainty and avoid such litigation we suggest that an amendment be made to §1(2); ch. 90, SLA 1978 to bring it back into conformity with its original language.

It is appropriate for the legislature to make the determination of whether the Act promotes a public purpose, rather than leaving the determination to the courts. If the legislature has any doubts as to whether the actual implementation of Authority powers will promote a public purpose, it may not approve the financial impact plan or it may impose certain conditions to insure that a public purpose is actually accomplished.

ATTACHMENT B

Draft Revisions

Sec. 44.55.090. Bonds of the authority. (a) The authority may borrow money and issue revenue bonds, in one or more series, [THE INTEREST ON WHICH IS EXEMPT FROM FEDERAL INCOME TAX EXCEPT WHEN HELD BY A SUBSTANTIAL USER OR RELATED PERSON AS DEFINED IN § 103 OF THE INTERNAL REVENUE CODE OF 1954 AS AMENDED,] up to the principal amount of $1,000,000,000 inclusive of amounts required for [FUND] reserves, capitalized interest, and costs of issuance of the bonds [OR NOTES] and exclusive of refunding bonds. Bonds of the authority may be issued for the corporate purposes of the authority including (1) financing or refinancing part of the cost of the project, or part or all of the cost of any part of the project, (2) purchasing or otherwise acquiring any obligation issued with respect to the project in any form which is fixed and certain as to terms of repayment and (3) for the establishment of reserves to secure or to pay bonds [OR NOTES] or interest on bonds [OR NOTES] and all other costs of the authority incident to and necessary for issuance of bonds. [OR NOTES.] The principal of and interest on the bonds [ARE] of the authority shall be payable from the income and receipts or other money derived by the authority with respect to the project, except to the extent payable out of money attributable to the proceeds of the sale of the bonds or out of income from the [TEMPORARY] investment of those proceeds.

Bonds may be issued by the authority only after approval by the legislature by concurrent resolution of a financial and Alaska Impact Plan and only in accordance with a separate concurrent resolution of the legislature approving the issuance of such bonds. The resolution approving the bonds may contain such limitations or conditions to the issuance of bonds as the legislature deems appropriate.

(b) The bonds issued by the authority do not constitute an indebtedness or other liability of the state or of a political subdivision of the state, but are payable solely from the income and receipts or other money of the authority. The authority may not pledge the faith or credit of the state or of a political subdivision of the state to the payment of a bond, and the issuance of a bond by the authority may not directly or indirectly or contingently obligate the state or a political subdivision of the state in any manner, except as specifically provided in this chapter.

(c) Bonds shall be authorized by resolution of the authority and shall be dated and mature as the resolution provides. Bonds shall bear interest at the rate or rates, be in the denominations, be in the form, either coupon or registered, carry the registration privileges, be executed in the manner, be payable at such times, in the medium of payment, at the place or places, and be subject to the terms of redemption which the resolution provides.

(d) All bonds, regardless of form or character, are negotiable instruments for all the purposes of the Uniform Commercial Code.

(e) All bonds may be sold at public or private sale in the manner, for the price, and at the time or times which the authority determines.

(f) The authority may enter into financing agreements necessary or desirable to secure the bonds. Before the issuance of bonds, the authority shall make provision by agreement with the owner or user of the project for payment by the owner or user of amounts at least sufficient in the judgment of the authority to pay the principal of and interest on the bonds as they become due, and to establish or maintain [THE] reserves for payment, if any, as the authority considers necessary or desirable.

(g) Refunding [OBLIGATIONS] bonds may be sold or exchanged for outstanding [OBLIGATIONS] bonds issued under this chapter subject to legislative approval as required by this section. If sold, the proceeds may be applied, in addition to other authorized purposes, to the purchase, redemption or payment of the outstanding [OBLIGATIONS] bonds to be refunded. Pending the application of the proceeds of any refunding [OBLIGATIONS] bonds, with any other available funds, to the payment of the principal, [()]accrued interest and any redemption premium on the [OBLIGATIONS] bonds being refunded[,] (and if so provided or permitted in the authorization for issuance of the refunding [OBLIGATIONS] bonds, to the payment of any interest on the refunding [OBLIGATIONS] bonds and any expenses in connection with the refunding), the proceeds may be invested in direct obligations of, or obligations the principal of and the interest on which are unconditionally guaranteed by,

the United States of America which mature or which will be subject to redemption, at the option of the holders of them, not later than the respective dates when the proceeds, together with the interest accruing on them, will be required for the purposes intended.

Draft Revisions

Sec. 44.55.110. LEGISLATIVE APPROVAL. [EITHER HOUSE OF THE LEGISLATURE MAY DISAPPROVE THE FINANCIAL AND ALASKA IMPACT PLAN OR AN AMENDED VERSION OF THE PLAN AND THE SALE OF REFUNDING BONDS BY A SIMPLE RESOLUTION. IF THE PLAN OR AN AMENDED VERSION OF THE PLAN OR THE SALE OF REFUNDING BONDS IS NOT APPROVED OR CONDITIONALLY APPROVED BY THE LEGISLATURE WITHIN 60 DAYS AFTER PRESENTATION TO THE LEGISLATURE, IT IS DISAPPROVED. THE LEGISLATURE MAY BY CONCURRENT RESOLUTION APPROVE THE PLAN OR AN AMENDED VERSION OF THE PLAN WITH] The legislature may approve the financial and Alaska impact plan by concurrent resolution. The approval may be subject to conditions concerning matters included in the plan or amended version of the plan, and the conditional approval becomes effective upon certification to the legislature by the authority that the authority has accepted the conditions and modified the plan in accordance. [NO BONDS OR NOTES MAY BE ISSUED OR SOLD UNTIL THE APPROVAL REQUIRED BY THIS SECTION HAS BEEN OBTAINED, AND NO BONDS OR NOTES MAY BE ISSUED OR SOLD EXCEPT IN ACCORDANCE WITH THE APPROVED PLAN.] The legislature must approve the plan, or an amended version of the plan within 60 days of its presentation to the legislature. Subject to the provisions of A.S. 44.55.140, later amendments to the plan may be adopted in the same manner as provided for initial approval by the legislature. After approval of the financial and Alaska impact plan, the legislature may approve the issuance of bonds as provided in A.S. 44.55.090.

[AMENDMENTS TO THE PLAN MAY BE SUBMITTED BEFORE THE PASSAGE BY THE AUTHORITY OF THE RESOLUTION AUTHORIZING THE SALE OF BONDS AND BECOME EFFECTIVE UPON APPROVAL BY THE LEGISLATURE BY CONCURRENT RESOLUTION.]

Draft New Section

Sec. 44.55.135. OPERATION OF A.S. 37.10.085. The authority shall not be considered to be the state or a political subdivision of the state for the purposes of A.S. 37.10.085.

Draft Revisions

Sec. 44.55.140. Pledge of the state. The state pledges to [AGREE WITH] the holders of bonds issued under this chapter that the state will not limit or withdraw the power of the authority to issue bonds approved by the legislature pursuant to A.S. 44.55.090 once an initial series thereof has been issued and will not limit or alter the rights and powers vested in the authority by this chapter to fulfill the terms of any contract made by the authority with those holders, or in any way impair the rights and remedies of those holders until the principal amount of the bonds, together with interest on them, with interest on unpaid installments of that interest, and all costs and expenses in connection with any action or proceeding by or on behalf of those holders, are fully met and discharged. The authority is authorized to include this pledge and agreement of the state in a contract with those holders.

Draft New Section

Sec. 44.55.145. EARNINGS OF THE AUTHORITY. The earnings of the authority in excess of the amount required for the retirement of indebtedness or the accomplishment of the purposes stated in this chapter may not inure to the benefit of any person other than the State.

Draft New Section

Sec. 44.55.155. DISPOSITION OF AUTHORITY PROPERTY UPON DISSOLUTION. Upon dissolution of the authority, title to all property owned by the authority will vest in the state.

Draft Revision

Sec. 44.55.200(2). "bonds" means bonds, notes, or other evidence of indebtedness of the authority, including bond anticipation notes or other obligations issued to provide interim financing for the project.

AGO 533058

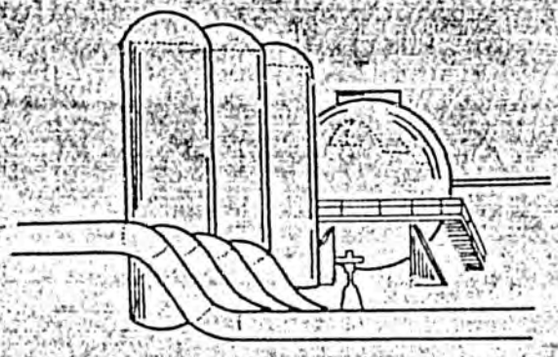
Draft Revision

Sec. 44.55.200(5). "project sponsor" means [ANY PARTNER OF] the Alaska Northwest Natural Gas Transportation Company, or its partners or [ITS] successors,[;] or any company, individual or association which owns an interest in the project or any part thereof;

PLEASE NOTE: THE PRECEDING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

COMMUNITY INFORMATION CENTER
INSTATE GAS ALTERNATIVES (EATBA)

Special Report No. 1
March 31, 1978



FAIRBANKS PETROCHEMICAL STUDY

by

Dr. John A. Kruse

Institute of Social and Economic Research

University of Alaska

FAIRBANKS NORTH STAR BOROUGH, COMMUNITY INFORMATION CENTER
Box 1267, Fairbanks, Alaska 99707
Location: 520 Fifth Avenue Phone: (907) 452-4761

AGO 533060

FAIRBANKS NORTH STAR BOROUGH
Box 1267, Fairbanks, Alaska 99707

COMMUNITY INFORMATION CENTER

Special Report No. 1

March 31, 1978

FAIRBANKS PETROCHEMICAL STUDY

By

Dr. John A. Kruse
Institute of Social and Economic Research
University of Alaska

FOREWORD

This study was funded by a $37,000 appropriation from the Borough Assembly using a combination of federal anti-recession fiscal assistance funds and the Assembly budgetary reserve. Production and publication costs for this report were shared by the Community Information Center, the Environmental Services Department, and the Planning Department. A special thanks to Marsha Bauman and Heidi Sciore who drafted the figures and Cindy Lippincott who typed the report.

ADVISORY BOARD:
Chris Stephens, Chairman
Dennis Weaver, Vice-chairman

Members: Rita Allee, Don Hart, Phil Deisher, Lottie Fleeks, Leslye Korvola, Terry Palczer, Bill Phillips, Wayne Thomas.

BOROUGH MAYOR:
John A. Carlson

COMMUNITY INFORMATION CENTER STAFF:
Sue Fison, Director
Laurie Rockstad, Assistant

LOCATION & PHONE:
520 Fifth Avenue
Second Floor
(907) 452-4761

MAILING ADDRESS:
P.O. Box 1267
Fairbanks, Ak. 99707

AGO 533061

ACKNOWLEDGEMENTS

Several individuals performed major roles in the execution of this study. Dr. Arlon Tussing, Dr. Louis York and Dr. Gordon Harrison were primarily responsible for the formulation of the petrochemical development scenario. Each was able to draw upon an impressive amount of personal knowledge and to assemble the required additional information within an extremely short period of time. Dr. Tussing in particular deserves a special note of thanks for his willingness to assume the time-consuming task of developing basic petrochemical scenarios when an unanticipated delay threatened the successful completion of the entire project.

Ms. Virgene Hanna performed magnificently as the project field director. As a result of her efforts, and the efforts of the 32 interviewers and coders she supervised, the field phase of the project was successfully completed ahead of schedule.

Ms. Sue Fison and the staff at the Borough Community Information office were able and willing to help throughout the study. I would also like to acknowledge the special efforts of Mrs. Donna Schuster in preparing the text and tables for the entire report. The final, but most important, acknowledgement is to the 436 Fairbanks residents who generously gave their time and opinions.

AGO 533062

TABLE OF CONTENTS

		Page
LIST OF TABLES		ii
LIST OF FIGURES		iv
Chapter		
1	INTRODUCTION	1
2	A DESCRIPTION OF PETROCHEMICAL DEVELOPMENT	7
3	GENERAL ATTITUDES AND EXPECTATIONS ABOUT GROWTH IN THE FAIRBANKS AREA	25
4	PUBLIC ATTITUDES AND EXPECTATIONS REGARDING PETROCHEMICAL DEVELOPMENT	37
5	REVISED ATTITUDES AND EXPECTATIONS BASED ON THE PETROCHEMICAL DEVELOPMENT DESCRIPTION	49
6	ATTITUDES TOWARD ALTERNATIVE GOVERNMENT ACTIONS WITH REGARD TO PETROCHEMICAL DEVELOPMENT	65
7	CURRENT ECONOMIC CONDITIONS IN FAIRBANKS	73
APPENDIX :	RESEARCH METHODS	87

AGD 533063

LIST OF TABLES

Table		Page
2-1	Alaska Natural Gas Conversion - Stearns-Roger.	14
2-2	Alaska Natural Gas Conversion - Dr. Arlon Tussing.	16
2-3	Comparison and Synthesis of Petrochemical Scenarios. . . .	16
3-1	Public Expectations for Growth in Fairbanks.	26
3-2	Attitudes Toward Expected Changes in Fairbanks	29
3-3	Expectations Regarding the Overall Pattern of Change in Fairbanks	32
3-4	Relative Importance of Specific Change Expectations in the Overall Evaluation of Future Change	33
3-5	Reasons for Staying in Fairbanks	34
3-6	Comparison of Overall Community Assessments of Change. . .	35
3-7	Growth Preferences	36
4-1	Fairbanks with Petrochemical Development	38
4-2	Public Estimates of Direct Effects of Petrochemical Development.	39
4-3	Public Expectations for Growth in Fairbanks with and without Petrochemical Development.	41
4-4	Comparison of Rates of Increase.	45
4-5	Comparison of Overall Assessments of Change in Fairbanks in General and Assuming Petrochemical Development.	46
5-1	Public Awareness of Differences Between Their Own Expectations and Estimates Contained in the Petrochemical Development Description	50
5-2	Major Differences Between Public Expectations and the Petrochemical Development Description.	51
5-3	Perceived Benefits and Costs of Petrochemical Development	53
5-4	Comparison of Rates of Increase.	58

AGO 533064

LIST OF TABLES (Cont.)

Table		Page
5-5	Comparison of Overall Assessment of Changes Expected in Fairbanks	61
5-6	Assessments of Changes with Petrochemical Development by Key Respondent Characteristics	62
6-1	Support for Borough Inviting Petrochemical Company Proposals and Supplying Information	66
6-2	Support for Giving Tax Break to Encourage Petrochemical Development	69
6-3	Support for Borough Selling Tax Free Bonds to Encourage Petrochemical Development	70
6-4	Support for State Selling Gas at Less than Full Value to Encourage In-state Petrochemical Development	71
7-1	Changes in Employment Status	73
7-2	Plans to Move from Fairbanks by Employment Status	74
7-3	Changes in Occupation 1976-1978	75
7-4	Changes in Occupation and Hours Worked among the Employed 1976-1978	76
7-5	Changes in Occupation among the Unemployed 1976-1978	76
7-6	Employment by Industry for Currently Employed and Unemployed	77
7-7	Effects of Pipeline Completion on Employment	78
7-8	Income Changes among Persons Living in Fairbanks since December 1972	80
7-9	Household Expenditures 1976 and 1978	81
7-10	Indication of Population Change	83
7-11	Housing Trends in Fairbanks	84
7-12	Housing Costs in Fairbanks	85
7-13	Age and Education Comparisons 1976 versus 1978	85

AGO 533065

LIST OF TABLES (Cont.)

Table		Page
7-14	Borough Concerns	86
A-1	Sampling Information	87

LIST OF FIGURES

Figure		Page
2-1	Stearns-Roger Flow Diagram for Petrochemical Facility. . .	13
2-2	Flowchart for Petrochemical Facility	23
2-3	Effects of Petrochemical Development	24
3-1	Average Expectations for Change in Fairbanks over the Next Ten Years	27
3-2	Average Expectations for Change in Fairbanks over the Next Ten Years Arranged According to Attitudes Toward Change	31
4-1	Percent of Maximum Rate of Change Expected with and without Petrochemical Development for 14 Community Attributes	42
4-2	Comparison of Average Rates of Expected Change with and without Petrochemical Development.	47
5-1	Comparison of Expected Rate of Change Before and After Presentation of the Petrochemical Description.	54
5-2	Comparison of Average Rate of Increase Expected.	57
5-3	Revised Average Expectations for Change Assuming Petrochemical Development.	60
7-1	Median Household Income for Fairbanks Residents: 1973 to 1977.	79

AGO 533066

Chapter One

INTRODUCTION

This report contains the results of work performed under Fairbanks North Star Borough Ordinance Number 7720II. The central objective of Ordinance Number 7720II is to assess the views of Fairbanks residents concerning petrochemical development in the Fairbanks North Star Borough. To achieve that objective, the Institute of Social and Economic Research at the University of Alaska initiated a study in January, 1978, which consisted of two major components. The first component involved the development of a comprehensive description of the most likely form of petrochemical development which could conceivably occur in the Fairbanks area. The description is based on a review of relevant technical and economic factors by a team of experts employed by the Institute. The second component of the ISER study consisted of a survey of Fairbanks residents which incorporated the petrochemical development description and met the rigorous sampling requirements necessary to insure that the results accurately reflect the views of all adults living in the Fairbanks North Star Borough.

The design of the petrochemical description and survey components of the study, in fact, reflects not only the overall study objective of assessing public attitudes concerning petrochemical development but also several specific sub-objectives. The results contained in this report can best be interpreted in the context of these sub-objectives so we have discussed each sub-objective in detail before the actual study findings are presented. Chapter One concludes with a brief summary of the results. Chapter Two presents the backup material that was used to generate the petrochemical description and Chapters Three through Seven contain a detailed discussion of the results of the survey. A description of the methods employed in conducting the survey and a copy of the questionnaire are included as Appendices A and B, respectively.

Sub-objective One: Presentation of a Description of Petrochemical Development

The topic of petrochemical development has appeared in over 20 articles in the Fairbanks Daily News-Miner in the past 2 months. While the public has been exposed to a vast amount of material on petrochemical development, the information has had the effect of increasing rather than diminishing the confusion which appears to surround public opinion on the issue. Even the most accurate reporting of statements and events cannot overcome the bewildering mix of facts, expert opinions and conjectures which broadly relate to the petrochemical industry. For this reason, it was felt that a simple polling of public opinion would do little to improve the information base used by the Borough

AGO 533067

Assembly and Administration in the formulation of Borough policies regarding petrochemical development. The selected alternative approach has involved a substantial effort to clarify the meaning of petrochemical development as it pertains to the Fairbanks situation. While it is impossible to precisely project all the effects a petrochemical plant would have on the Fairbanks community, we have attempted to objectively review the set of technical, economic and environmental factors upon which public attitudes toward petrochemical development are based. This information has been presented to a scientifically selected sample of over 400 Fairbanks residents. We hope that the information will also become a focal point of discussion for the Fairbanks community as a whole. At the same time, we have designed the study in a way that will enable us to project what public attitudes would be regarding petrochemical developments which dramatically diverge from our own best estimates. Consequently, the results of this study should not become quickly outmoded as events transpire and new information is developed. Details about how the petrochemical development description was developed appear in Chapter Two. Public attitudes toward petrochemical development that are in part based on the petrochemical development description are discussed in Chapter Five.

Sub-objective Two: Assessment of Attitudes of the General Public Toward Petrochemical Development

It is important to remember that the petrochemical development description incorporated in the survey at best clarified the issue for two percent of the Fairbanks population. Even assuming that a successful community-wide information dissemination program is implemented, the majority of Fairbanks residents are likely to remain relatively uninformed about the changes that would be expected to result from a petrochemical development. If a referendum is conducted on the issue in the future, a substantial proportion of those voting may not have been exposed to a comprehensive description of the effects of the most likely petrochemical development in the Fairbanks area. It is, therefore, important to know the attitudes of potential voters who have not read or heard the petrochemical description. Because the survey sample accurately represents all Fairbanks residents, it is possible to meet this objective by asking a series of questions in the interview about petrochemical development before the petrochemical description is presented. In this way, the results of the survey reflect both the attitudes of the general public as well as the attitudes of a sample of the public that has been presented with detailed information about the most likely form of petrochemical development. Results reflecting the attitudes of the general public toward petrochemical development are presented in Chapter Four.

Sub-objective Three: Assessment of Expectations Concerning Petrochemical Development

Attitudes describe what people like or dislike about an object and

AGO 533068

are based on the basic values a person holds and the information they possess about the object. Although the petrochemical development description is designed to provide a uniform set of information, people are at liberty to disagree with this information and base their attitudes on information from other sources. In addition, the survey also assesses public attitudes before the petrochemical description is presented. In both instances, we need to know what information people are actually using as a basis for their attitudes. This information can best be described as a set of expectations about the changes that would result from petrochemical development in the Fairbanks area. The survey thus includes not only measures of public attitudes toward petrochemical development but also measures related to what people expect from a petrochemical devllopment. A discussion of general public expectations regarding petrochemical development can be found in Chapter Four. Results reflecting expectations which have been revised on the basis of the petrochemical development description appear in Chapter Five.

Sub-objective Four: Assessment of General Growth Attitudes and Expectations

Attitudes and expectations concerning petrochemical development cannot be divorced from the more general set of attitudes and expectations concerning growth and change in the Fairbanks area. The potential effects of petrochemical development must be compared with the expected course of changes that will result from other sources of economic growth such as agriculture, tourism and other industries. Of course, a general assessment of attitudes and expectations toward growth not only establishes the necessary comparative perspective but also provides a valable body of information in itself. The results of this assessment appear in Chapter Three.

Sub-objective Five: Assessment of Current Fairbanks Economic Conditions

The Fairbanks Petrochemical Study is primarily oriented toward the future but the survey presents an opportunity to collect valuable information about the present as well. Since economic conditions in Fairbanks affect almost every Borough policy, a current assessment is included as a sub-objective of the study. The survey focuses in particular on the current employment status of the population with additional questions on housing, moving plans, and past and expected major purchases. Together, the results of these questions will present a detailed picture of the current level of economic well-being in the Fairbanks community.

A major survey of the type performed in this study also yields a variety of information which is ancillary to the central objectives of the study but extremely valuable in other contexts. One such information byproduct is a detailed breakdown of the current demographic characteristics of the Fairbanks population. Another is a listing of key concerns

AGO 533069

people would like the Borough to know about. Information relevant to current economic conditions in Fairbanks and information not directly related to the central objectives of this study appear in Chapter Five.

Summary of Results

Survey results show that residents expect Fairbanks will continue to grow over the next ten years, but at a slower rate than that of the last several years. They believe that hunting and fishing opportunities and the quality of the air in Fairbanks have declined in recent years, and residents expect both community attributes to continue their decline at a moderate rate over the next ten years. Most other community attributes, such as the number of job opportunities, locally made products, new stores, and the amount of services provided by the Borough are only expected to increase slowly. Roughly a third of the Fairbanks population expect these attributes to remain at about current levels.

In responding to what specific changes they thought would occur over the next ten years in Fairbanks, most residents expected that undesirable[1] community attributes such as the amount of air pollution and population growth to increase more rapidly than such desirable attributes as the number of job opportunities and locally made products. However, when asked their overall expectations for change in Fairbanks, 76 percent of the population expected that Fairbanks would be just as good or a better place to live over the next ten years. The discrepancy is in part accounted for by the fact that slow increases in several desirable community attributes are considered more important than larger increases in some of the least desirable community attributes. Survey results also show that residents who are staying in Fairbanks primarily for economic reasons tend to expect the community to become a better place to live while those who are staying in Fairbanks primarily to take advantage of the surrounding wilderness environment tend to expect Fairbanks will become a worse place to live over the next ten years.

The results of the survey confirmed our expectation that few people agree about the direct effects of petrochemical development. While many residents believe that they are at least somewhat familiar with petrochemical development (69 percent), their expectations before being presented with our description of petrochemical development varied widely. For example, 26 percent of the population expects that a petrochemical facility would employ 100 or fewer persons, while 29 percent expect that over 500 persons would work at such a plant. Overall, most residents indicated that the primary effects of petrochemical development would be to create jobs, produce goods for local consumption and increase the amount of air pollution.

---

[1] The desirability of community attributes was determined by the respondents themselves.

AGO 533070

On balance, the same proportion of Fairbanks residents (29 percent) expect that a petrochemical plant would make Fairbanks a better place to live as expect it would make Fairbanks a worse place to live. Over a third of the population (35 percent) expected that petrochemical development would not affect their lives for the better or worse, and 7 percent simply did not know what to expect.

The description of petrochemical development presented to our survey respondents did have the desired effect of correcting much of the misinformation and reducing the confusion about petrochemical development. Several aspects of the description differed from general public conceptions about petrochemical development. First, the facility would cost more than residents would have expected and such a facility would add a substantial amount to the local tax base. Second, the construction of the plant would result in the employment of more people than most residents realized. Third, a petrochemical plant of the type most likely to be constructed in Fairbanks would not result in the smog initially expected by most residents. Finally, the plant would not result in many new products becoming available locally.

After being presented with the petrochemical development information, residents modified their expectations about resulting changes in 7 of the 14 major community attributes. They expected more rapid increases in the amount of taxable property, the quality of transportation links to Fairbanks, and in the amount of Borough services provided. In addition, they expected less rapid increases in the number of locally available products, the amount of air pollution, the number of new stores, and the number of jobs related to agriculture.

Respondents now expect that while there will be somewhat more growth with petrochemical development than without it, the growth will follow patterns similar to that expected to occur without the development.

Public attitudes on how such development will affect the quality of living in Fairbanks did not change substantially overall buy many individuals changed their attitudes after learning more about petrochemical development. The net result is that our informed sample of Fairbanks residents divided about equally (28 versus 26 percent) over whether petrochemical development would make Fairbanks a better versus worse place to live with 3 percent having no opinion. The remaining 43 percent of the sample did not expect petrochemical development to affect Fairbanks one way or the other. Nevertheless, most of the residents who did not expect petrochemical development to affect Fairbanks for better or worse tended to favor petrochemical development.

When asked whether the Borough should invite petrochemical companies to make proposals and if it should aid in developing information required by petrochemical companies, 67 percent of our respondents said yes. This question was asked after information was presented to the respondents on most likely effects of petrochemical development and thus reflects the attitude of an informed sample of the Fairbanks population.

It first appears strange that only 29 percent of the respondents

expect that petrochemical development would make Fairbanks a better place to live, while 67 percent favor the Borough's promotion of petrochemical development. The 38 percent difference is explained by the petrochemical development leanings of those who think petrochemical development would not change Fairbanks for better or worse.

Support for petrochemical development can be assumed in two ways. If we count those who would just as soon have petrochemical development as not, there is considerable support. However, as mentioned above, this support does not accurately reflect the number of people who actually expect Fairbanks living conditions to improve as a result of petrochemical development. Alternatively, if we count those who expect to gain as being for development and those who expect to lose as being against, the levels of support and opposition for petrochemical development are equal. However, this approach ignores the preferences of 43 percent of the population who expect to neither gain or lose should petrochemical development occur.

The survey results do not directly establish what Borough policy should be, but they do furnish a basis on which Borough policy can be formulated. Since there is not a concensus supporting or opposing development, an equitable solution would require a tradeoff between the views of 26 percent of the population who expect petrochemical development will make Fairbanks a worse place to live and 43 percent of the population who don't expect to gain or lose as a result of petrochemical development, but who support it anyway.

Apart from the question of whether the Borough should support, oppose or remain neutral with regard to petrochemical development, survey respondents were asked for their views on several specific actions that could be taken to increase the economic feasibility of petrochemical development. The results indicate that most Fairbanks residents would like to encourage petrochemical development as long as it does not cost much to do so. The public believes that the Borough should pursue such inexpensive activities as inviting companies to make proposals and providing them with information. However, the majority of Fairbanks residents does not support such possible economic incentives as tax breaks, the sale of municipal revenue bonds to help finance development, or the sale of State royalty gas at less than full value. The lack of support for these incentives appears to reflect the fact that most residents do not expect petrochemical development to make Fairbanks a better place for them to live. Roughly, a third of the population does expect petrochemical development to make Fairbanks a better place to live, and we repeatedly find that about a third of the population support incentives which involve some sacrifices.

The following chapters take a much closer look at the survey results. The above summary is only intended to highlight the most important findings; the residents of Fairbanks provided a great deal more information than we have been able to cover here and we hope that the detailed discussion forming the main body of this report is more successful in capturing the rich fabric of attitudes and expectations regarding growth in general and petrochemical development in particular.

AGO 533072

Chapter Two

A DESCRIPTION OF PETROCHEMICAL DEVELOPMENT

Petrochemicals are defined as chemicals derived from petroleum raw materials, including natural gas. They are the basic building blocks for thousands of products such as fertilizers, plastics, fibers, paints, solvents and many varieties of rubber. Whether a petrochemical industry can be located in Fairbanks and what type of petrochemical development would be best suited for Fairbanks are questions which involve dozens of facotrs. Among them are: the type of petroleum raw materials available, the cost of these raw materials, the cost of building and operating the plant, the availability of skilled labor, water, land, services for employees and adequate transportation facilities, the location of markets for petrochemicals, the location of other chemicals which can be used in a petrcchemical plant, the cost of transporting both the inputs to and outputs from the plant, the price and demand for petrochemical products, the presence of environmental constraints, zoning regulations, property and income taxes as well as an equally extensive list for all alternative uses of the raw materials in Fairbanks and elsewhere. The above enumeration is probably no more, or less, extensive than that which might be given for any major industry. It should serve to make the point, however, that a description of petrochemical development must be based on many assumptions about factors whose characteristics are still uncertain. The price of North Slope natural gas is unknown. Even the content of the gas that will ultimately be in the Northwest gas pipeline is in question. At the same time, world production and consumption of petrochemicals are expected to change rapidly in the next decade.

It is easy to see why discussions about petrochemical development involve many confusing and often contradictory statements. It is also clear that it is impossible to describe the exact form of petrochemical development which might occur in Fairbanks or even to say at this point whether it is technically and economically feasible to construct such a plant in the Fairbanks area. We can, however, formulate a reasonably concrete description of the most likely technically feasible and economically conceivable facility. The range of projected effects can be considerably narrowed from that which applies to the petrochemical industry as a whole. For example, we are talking about a gas-based and not oil-based petrochemical plant. A description of the effects of oil-based petrochemical plants is appropriate for Kenai or Valdez, not Fairbanks. Another example of how the range of effects can be narrowed concerns the petrochemical products that can be expected from a plant located in Fairbanks. There are clear economic reasons why such a plant cannot produce final products such as tires and molded plastics. The remainder of this chapter is devoted to a brief discussion of the basic concepts that are relevant to petrochemical development in Fairbanks, followed by a technical description of the more likely forms of petro-

AGO 533073

chemical development and concluding with the text of the petrochemical development description that was presented to our survey respondents.

BASIC CONCEPTS - Feedstock Sources.

We have assumed that the Northwest Alaskan (NWA) gas pipeline will carry only "dry" gas, i.e., a mixture of methane and ethane with only traces of propane, butane and heavier hydrocarbons, and that a separate gas liquids pipeline would be required to transport significant quantities of propane and butanes to or beyond Fairbanks. The small quantities of natural gasolines (pentanes plus) extracted from the natural gas stream can be transported either in such a liquids pipeline or mixed with the crude oil in the Alyeska oil pipeline.

While it is technically possible to move "wet" gas in the NWA natural gas pipeline, or to dissolve propane and butanes in the crude oil stream for movement in the oil pipelines, the authorities we have consulted regard these alternatives as unlikely economically. Thus we have assumed that three main possibilities exist for petrochemical feedstock sources in the Fairbanks area based upon natural gas production from Prudhoe Bay.

The first potential source of feedstocks is to remove some portion of the dry gas stream (methane and ethane) from the NWA pipeline at Fairbanks and to use these gases for petrochemical manufacturing in about the proportion in which they will be mixed in the processed gas stream from Prudhoe Bay. Any excess of either gas resulting from an imbalance of plant requirements relative to the proportion of gases in the gas supply would be returned to the NWA pipeline for shipment out of Alaska.

The second potential source of feedstocks is to process a part of the dry gas stream at Fairbanks, removing ethane for petrochemical manufacture and returning the methane to the NWA pipeline for shipment out of Alaska.

The third potential source of feedstocks is liquids from a processing plant at Prudhoe Bay, moved by a gas liquids pipeline from Prudhoe Bay to or beyond Fairbanks. This liquids stream could be composed of ethane, together with propane and butanes (perhaps with some natural gasolines) or alternatively all or most of the ethane could be retained in or returned to the gas stream in the NWA pipeline at the processing plant.

For the purpose of planning a petroleum complex, a fourth feedstock option is a combination of the preceding, using methane and ethane drawn from the NWA gas pipeline at Fairbanks with ethane, propane and butane from a gas liquids pipeline.

AGO 533074

BASIC CONCEPTS - Transportation of Feedstocks.

The NWA gas pipeline will carry a mixture mainly of methane and ethane, so that this pipeline can be a source of either or both. Thus, it would not require a separate transportation facility to make either feedstock available to a petrochemical plant in Interior Alaska. Ethane, however, could also be moved to Fairbanks in a 440-mile gas liquids pipeline along with some or all of the heavier gas liquids. Moving all of the ethane, butane and propanes corresponding to 2.0 billion cubic feet per day of pipeline gas would probably require an 18-inch pipeline. If the ethane were retained in the gas pipeline, a 12-to 14-inch pipeline would be required to move all of the available propane and butanes. Moving only the volumes of ethane, propane and butane required to serve a world-scale olefins (ethylene-propylene-butylene) complex would require an 8-to 10-inch pipeline. It is very unlikely that it would become economic to move gas liquids separately on any smaller scale.

BASIC CONCEPTS - Transportation of Petrochemical Products.

Most petrochemical products from Interior Alaska could be shipped either in a product pipeline or by rail. The larger volumes of methanol envisioned previously, however, conceivably could be shipped in batches through the trans-Alaska oil pipeline to Valdez.

Assuming that its output is entirely liquids, the output of a world-scale ethylene facility could be served by an 8-inch pipeline to tidewater at Haines, Valdez, Whittier or Cook Inlet, and a broad-range olefins facility would require a 10-inch pipeline. If all the State's royalty gas were converted to methanol, the methanol alone would require a 12-inch pipeline; a 14-inch pipeline would be required to carry 55,000 barrels per day of methanol, together with the products of a world-scale olefins plant. The maximum scale products pipeline that can be envisioned is one which would carry methanol, olefins products plus all of the natural gas liquids produced with the Prudhoe Bay gas and not utilized in the field, for pumping or in chemical manufacturing; a 20-24-inch pipeline would be required for this purpose.

The alternative mode of transportation is the use of rail cars on the Alaska Railroad to Whittier or Seward. A world-scale ethylene plant (300,000-500,000 tons per year) would need 30-60 100-car unit trains per year, depending upon the product mix. An ethylene-propylene-butylene complex might require as many as 90 such trains. The methanol produced from all the State's royalty gas would require as many as one additional unit train per day. According to the Alaska Railroad, such additional volumes are all within the present capacity of the railroad to move without major capital improvements.

AGO 533075

BASIC CONCEPTS - Petrochemicals from Methane.

The principal product from a petrochemical facility using methane from the NWA pipeline would be methanol. Other elementary methane derivatives which might be manufactured in such a facility are ammonia, acetylene, formaldehyde, urea and acrylonitrile. The volumes of any of these products that would be produced from processing the State's entire royalty gas stream (200 million cubic feet per day) would be very large in relation to existing North American consumption. The only methane product likely to be marketable in such quantities is fuel-grade methanol, the demand for which would be nearly unlimited at a price competitive with other clean-burning fuels in markets such as Southern California. Methanol could conceivably be used as boiler fuel or turbine fuel for electric power generation, or blended with motor gasoline or diesel oil in proportions up to 10 or 20 percent. Each million-cubic-feet-per-day facility would produce about 330,000 tons of methanol per year (5.5 mb/d). The State's royalty gas from Prudhoe Bay could conceivably support as many as ten such trains.

BASIC CONCEPTS - Petrochemicals from Ethane.

Ethane could be made available in Interior Alaska either from a gas processing plant extracting it from its mixture with methane in the NWA gas pipeline, or from a gas processing plant at Prudhoe Bay which would send the ethane, together with propane and butanes, through a gas liquids pipeline to or beyond Fairbanks. The principal use of ethane would be for manufacture of ethylene, which is the principal raw material for manufacture of polyethylene (high density and low density), ethyl alcohol and acetaldehyde, styrene (requires benzene), ethylene glycol and ethanolamine.

Any ethylene facility built in Interior Alaska would be of "world-scale," that is, of the most economical size assuming access to national and world markets. Such a plant would consume 13-21 mb/d of ethane and produce 300,000-500,000 tons per year of ethylene. Ethylene itself could be shipped by products pipeline or tank cars to tidewater for further processing elsewhere, or converted in the same plant to some of all of the products mentioned previously.

BASIC CONCEPTS - Petrochemicals from Propane and Butane.

Propane and butane extracted from the natural gas at a Prudhoe Bay processing plant might be transported to or beyond Fairbanks in a gas liquids pipeline, together with or apart from some or all of the ethane. The volumes of butane and propane corresponding to 2.0 bcf/d of pipeline gas (methane + ethane) are about 70mb/d and 10 mb/d respectively. A single world-scale propylene plant would utilize about 15mb/d of propane to produce about 130 million tons of propylene per year. Propylene might be further processed to isopropyl alcohol, acetone, cumene and

AGO 533076

polypropylene. Additional processing in Interior Alaska would be unlikely in the foreseeable future.

Butane can be cracked to butylene and further processed to n and t-butanol, methyl ethyl ketone, butadiene, butyl rubber, di- and tri-isobutane and polyisobutane. The size of a butane plant would be limited by feedstock availability rather than technology.

BASIC CONCEPTS - Further Processing.

Because of the severe capital and operating costs handicaps of operating in Interior Alaska compared to Lower 48 sites, the Far East or even tidewater locations in Alaska, it is unlikely that further processing beyond the products mentioned here to finished chemicals (pharmaceuticals, resins, paints, etc.) or plastic products would take place in Alaska. Comparatively high shipping costs for non-hydrocarbon raw materials would also make it unlikely that compounds involving halogens or sulphur would be produced locally.

The petrochemicals likely to be produced in an Interior Alaska plant would all tend to be liquids with relatively low vapor pressures or solids at ambient temperatures, relatively non-corrosive and without exceptional safety problems in handling.

Technical Descriptions

Technical descriptions of the types of petrochemical plants that conceivably could be located in the Fairbanks area were developed by three experts: Dr. Louis York, chief environmental scientist for Stearns-Roger, Dr. Arlon Tussing, professor of economics with ISER and Dr. Gordon Harrison, an economic consultant. Dr. York has had over 30 years experience in the fields of petroleum production, transportation, refining and in the assessment of the environmental effects of petroleum-related activities. He currently heads the environmental assessmental division of the world's largest petroleum engineering and construction firm. Dr. Tussing has been extensively involved in the economic analysis of energy developments and policies within Alaska. He has served as chief economist of the Senate's National Fuels and Energy Policy Study in 1974 and as a member of the Alaska Royalty Oil and Gas Development Advisory Board. Dr. Harrison has served as an economic consultant with the firm of Dames and Moore, developing projections of construction schedules and manpower requirements for such projects as the Atlantic Richfield Trans-Mountain pipeline project and for the Bureau of Land Management-Outer Continental Shelf Studies Program concerning offshore energy developments.

Initial project plans called for Dr. York, with the aid of engineers at Stearns-Roger, to develop estimates of the construction costs, direct employment and physical characteristics of one or more petrochemical

AGO 533077

facilities within a general range of facilities that was previously identified to be both technically feasible and economically conveivable. Dr. Harrison's project responsibility was to develop estimates of construction costs and manpower requirements for a gas liquids and a products pipeline. Estimates from both Dr. York and Dr. Harrison would be integrated by Dr. Tussing as a complete technical description to which he would add estimates of relevant indirect effects.

For reasons beyond his control, Dr. York was unable to provide Dr. Tussing with technical estimates on schedule. In order to maintain the extremely tight project schedule, Dr. Tussing proceeded to independently develop his own technical estimates. Thus, two sets of estimates were independently derived from this project. While the estimates are not entirely comparable, they are, in fact, quite similar. Dr. York assumes that all royalty gas will be removed at Fairbanks and processed through a separation plant to separate the methane from the ethane and a small amount of propane. The methane is assumed to be processed completely to methanol. The ethane and propane is assumed to be delivered to an ethylene plant, which then produces large amounts of ethylene and various quantities of other materials shown in Figure 2-1. The ethylene could be sold directly or could be converted to other products. York assumed two alternatives: conversion of all ethylene to polyethylene pellets or conversion of all ethylene to ethanol. The methanol and ethanol could be shipped as liquids in tank cars or by pipeline. The ethylene could be shipped as pressurized gas in cylinders or by pipeline. The polyethylene pellets are solid and could be shipped in closed hopper cars. A summary of the capital costs, process facilities, construction labor force requirements, operating costs and permanent labor force requirements under Dr. York's assumptions is given in Table 2-1.

Dr. Tussing developed four scenarios which range from the smallest to the largest technically feasible and economically conceivable facilities. In the first scenario, Dr. Tussing assumes that an ethylene plant would be constructed. Such a plant would be the simplest, lowest-cost world-scale petrochemical facility using North Slope feedstocks which is both technically feasible and economically plausible for Interior Alaska. Thirteen to twenty-one thousand barrels per day of ethane would be extracted from the gas stream (methane + ethane) in the Northwest Alaskan pipeline, and converted to 300-500 thousand tons per year of ethylene, which would be shipped to tidewater in special rail cars on the Alaska Railroad. No major roadbed or track improvements would be necessary to carry these volumes, but some additional railroad investment would be necessary for a spur track and terminal at the plant.

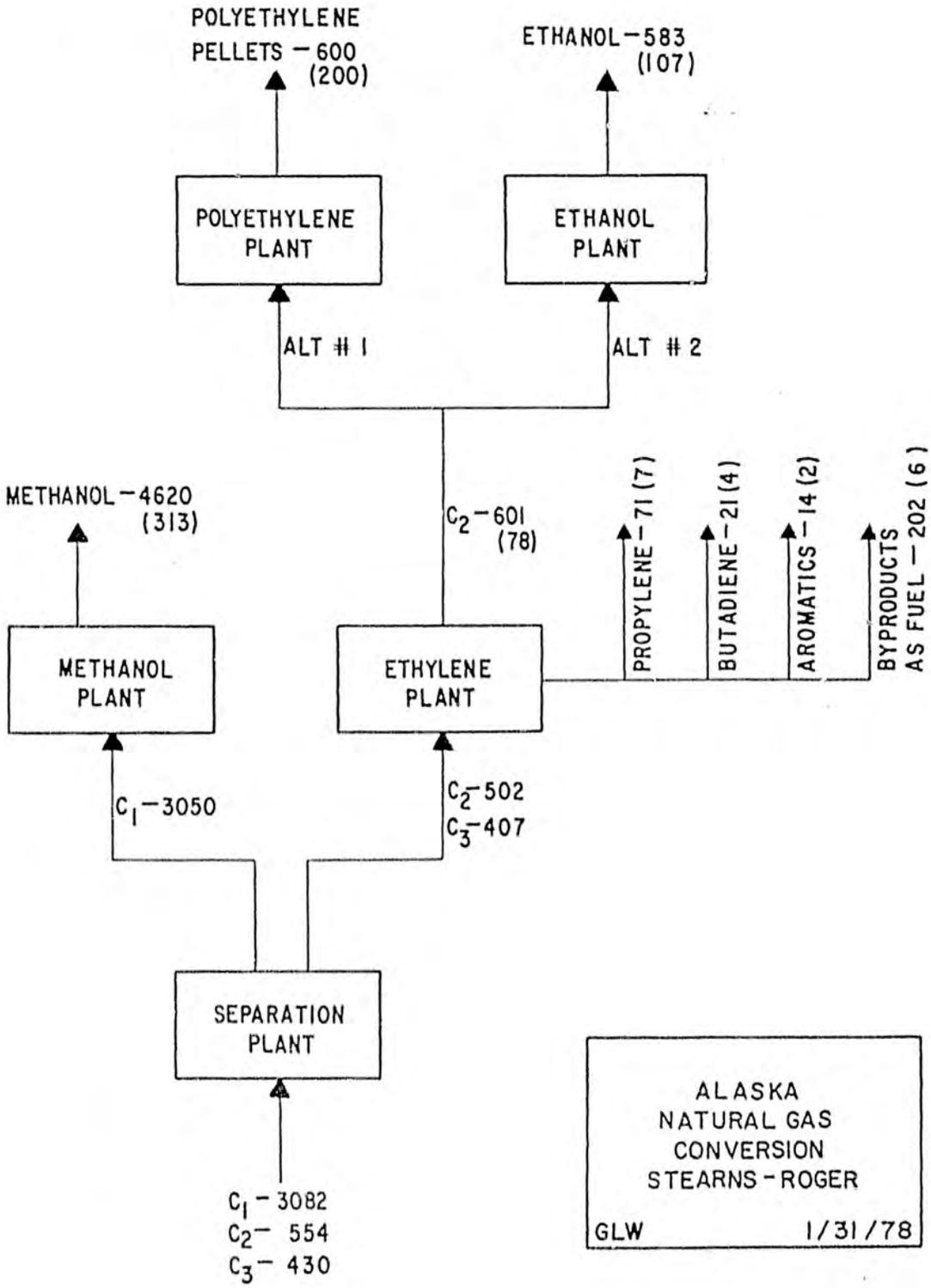
In the second scenario the State's entire royalty gas share (250 mmcf/d of methane and ethane) is used as feedstock for one 300-500 thousand ton per year ethylene plant as in the first scenario, or as feedstock to 10 facilities producing about 5.5 thousand barrels per day of fuel-grade methanol. Both products would be transported to tidewater by means of a 12-inch products pipeline.

AGO 533078

FIGURE 2-1

NOTES

1. FLOWS ARE GIVEN IN MM LB/YEAR
2. DOLLAR VALUE OF PRODUCTS IS GIVEN IN MM $/ YEAR -- SHOWN IN ( ).



AGO 533079

TABLE 2-1

Alaska Natural Gas Conversion

Stearns-Roger
C-20763

	Separation Plant	Methanol Plant	Ethylene Plant	Polyethylene Plant	Ethanol Plant
Capital Expenditure, MM$	67	399	271	218	90
Typical Process	Expander	ICI Low Pressure	Lummus	Tubular LDPE	Veba-Chemie AG
Peak Construction Force	400	2,000	1,450	1,200	400
Operating Costs, MM$/Yr	4	57	24	10	4
Permanent Employees (excluding 50 overall plant support positions)	120	160	145	165	130
Operating Lines	1	3	1	2	1

NOTES

1. Plant cost based on 1978 dollars. Costs must be escalated to projected completion date. Costs assumed 200% of Lower 48.
2. Plant location assumed to be near the Fairbanks area. No camp facilities or special offsites included.
3. Construction force given as 120% of Gulf Coast requirements.
4. Operating costs include labor, maintenance, and utilities only.
5. All estimates are order of magnitude only.
6. Engineering design time: 18 mos.
   Construction time: 40 mos.
   Average const. force for first three plants: 2,160

AGO 533080

The third scenario assumes that ethane, propane and butanes extracted from Prudhoe Bay natural gas on the North Slope are carried by an 8-inch gas liquids pipeline to the Fairbanks area, where they are used as feedstock for a world-scale olefins (ethylene, propylene and butylenes) steam-cracking facility. These olefins are further processed in the same complex into low- and high density polyethylene, ethyl alcohol, ethylene glycol, and (together with benzene purchased from the North Pole refinery) styrene monomer; acetone, propylene glycol, cumene, isopropyl alcohol and polypropylene; butanols, methyl ethyl ketone, butadiene, and isobutylenes). All these products (500-750 thousand tons per year) would be shipped to tidewater on the Alaska Railroad.

Finally, the fourth scenario describes the most extensive petrochemical development based upon Prudhoe Bay natural gas feedstocks which is technically feasible and economically plausible for Interior Alaska. It would use the State's entire royalty share of methane carried through the Northwest Alaskan gas pipeline, together with the entire stream of natural gas liquids produced from the gas processing plant on the North Slope, less the gas and liquids used as fuel in the field and as pump station fuel for the oil, gas and liquids pipeline. The liquids would be transported as far as Fairbanks in an 18-inch gas liquids pipeline. There would be a world-scale olefins complex as in scenario III, ten methanol trains as in scenario II, plus a 450,000 ton ammonia plant, a 500,000 ton urea plant, a 200,000 ton (37%) formaldehyde plant, and 50,000 ton ethanolamine and acrylonitrile facilities. Solids and liquids raising contamination problems would be transported by rail, while the remainder of the liquid products, plus the unutilized gas liquids, would be transported to tidewater in an 18-inch products pipeline.

Table 2-2 provides a summary of capital costs, construction estimates and permanent employment for the four scenarios developed by Dr. Tussing. A breakdown is also given by specific facility to permit a rough comparison to be made between Dr. York's and Dr. Tussing's estimates. The best comparison can be made between the first three columns of each table, thus including a separator, an ethylene and a methanol plant. The relevant figures are repeated in the first two columns of Table 2-3. Although derived independently, the estimates for required capital expenditures and permanent employment are not significantly different. Construction estimates do vary widely. Peak estimates will vary according to the timing of construction for each component of the plant, and Dr. York assumed all three plants would be built simultaneously while Dr. Tussing assumed that construction of the plants would be phased. It does appear, however, that a substantial difference between the estimates would remain even if common assumptions were made about the timing of the construction.

The scenario developed by Dr. York roughly corresponds to Dr. Tussing's second scenario. Dr. Tussing's third and fourth scenarios are considerably larger and more complex facilities. While Dr. Tussing has included them in the range of technically feasible and economically conceivable petrochemical developments, he cautions that it is extremely unlikely

AGO 533081

TABLE 2-2

Alaska Natural Gas Conversion
Dr. Arlon Tussing

	Capital Expenditure MM$	Peak Construction Force	Construction Duration (months)	Total Man-months Construction	Average Monthly Construction Employment	Permanent Employees
Separation Plant	71	710	18	8,520	473	65
Ethylene Plant	284	710	18	8,520	473	160
Methanol Plant	381	736	30	6,200	207	200
Ethylene, Propylene, Butylene Complex	1,641	2,317	18	30,250	1,681	1,040
Methane Prod. Olefins Com. Ethanol, Amine, Acrylonitrile Facility	2,164	1,880	30	19,060	1,744	1,335
12-inch Product Pipeline	132	389	12	2,400	200	10
8-Inch Gas Liquids Pipeline	120	1,778	12	11,784	982	25
18-Inch Gas Liquids Pipeline	146	2,108	12	14,280	1,190	30
18-Inch Product Pipeline	146	330	12	2,640	220	12
RR Spur & Terminal	-	240	12	1,440	120	10
Scenario I	355	830	18	9,960	553	250
Scenario II	868	856	30	17,120	571	435
Scenario III	1,952	2,517	30	50,344	1,678	1,160
Scenario IV	2,908	3,462	30	69,240	2,308	1,642

TABLE 2-3

Comparison and Synthesis of Petrochemical Scenarios

	Dr. Tussing's Estimates	Dr. York's Estimates	Addition of Ethanol Plant	Final Estimates for Petrochemical Complex
Capital Expenditure (millions)	736	737	90	830
Peak Construct. Work Force	1,450	3,850	400	3,000
Ave. Construct. Work Force	680	2,160	216	1,500
Permanent Work Force	425	475	130	600

AGO 533082

that economic conditions in the foreseeable future would be such as to justify processing North Slope natural gas beyond the most elementary products. Dr. Tussing suggested that it would be more realistic to rely only on scenarios I and II. A single question referring to the possibility of a much larger facility was, however, included in the survey.

To summarize the major scenarios developed by both Dr. Tussing and Dr. York, both assume that the methane and ethane from the Northwest gas pipeline will be separated and processed into methanol and ethylene. Furthermore, the permanent employment and capital cost estimates derived for each scenario are amazingly close. As a result, the integration of the two scenarios is relatively easy. Dr. York's scenario contains two alternative end products in the conversion of ethylene: ethanol or polyethylene. Both facilities are potential additions to Dr. Tussing's second scenario. It was felt that the best way to integrate scenarios was to add either the ethanol or the polyethylene processing facility to Dr. Tussing's second scenario. Ethanol was chosen as a product for the final scenario since the ethanol facility would be smaller than the polyethylene facility and the development of a smaller plant was considered more likely. The relevant figures for the ethanol plant appear as a third column in Table 2-3. Capital cost estimates for the basic facility agree closely, so there is little question about the assignment of a single best estimate for the complex as a whole (see Table 2-3). The same is true for the permanent workforce estimates. More judgment was involved in estimating average and peak construction employment. The final construction estimates, which appear in column four of Table 2-3, roughly correspond to the midpoint between the two estimates. Finally, it should be noted that Dr. Tussing's second scenario included a 12-inch products pipeline. To make the scenario easier to present to the public and since employment and capital costs for the products pipeline are minor compared to the petrochemical plant itself, cost and employment estimates were made only for the plant. The scenario did mention, however, that the petrochemicals would be transported by pipeline or rail.

The final scenario also mentions that few, if any, products would be available locally. This judgment is based on the fact that the local or even statewide market for petrochemical products is too small to warrant extensive processing of intermediate products for local distribution. Many such products would require the importation of chemicals to the Interior, thus adding substantial production costs. Final products that were available would be most profitably sold at just below current market prices. There was a strong concensus among the project staff that local products should not be listed among the likely benefits of a petrochemical facility located in the Fairbanks area.

The chemical processes involved in the final scenario clearly do not involve the pollutants that are associated with the oil-based petrochemical industry or with processes that require the addition of aromatic compounds or chemicals such as chlorine. The potential effect of water vapor emissions is more problematic. Providing stack emissions do not occur within

AGO 533083

about the first six hundred feet above the urban basin, it does not appear that a petrochemical plant would directly contribute to the ice fog which occurs at or near ground level. This judgment is based not only on a knowledge of the characteristics of petrochemical plant stack emissions but also on experience with similar emissions in the Fairbanks area.

The final area addressed in the petrochemical scenario is that of induced changes in employment and population. Traditionally applied employment multipliers are not appropriate for Fairbanks because much of the support sector employment increase generated by basic industry occurs in Anchorage. We assumed that the addition of five jobs in basic industry will result in one additional job in the support sector in the Fairbanks area. The projected population increase is based on the assumptions that two-thirds of the permanent jobs created will be filled by non-residents possessing the necessary skills and that the average family size of those moving to Fairbanks is 2.5. The exact number of indirect jobs created and the resultant population increase is, of course, impossible to predict. Under varying assumptions it is possible that both figures might be doubled. The important point is that the population will not increase by more than several percent nor will the number of permanent indirect jobs created be in any way comparable to that experienced during construction phase of the trans-Alaska pipeline.

Interviewers read the complete scenario to each respondent during the course of the interview. Respondents were also given a copy of the scenario and two diagrams (see Figures 2-2 and 2-3) to aid in remembering the points covered in the description. Following the presentation of the scenario, respondents were asked if they were confused about any statements or if they wished to hear parts of the scenario again. Interviewers were instructed to note which paragraphs were reread and to record any comments the respondent might make about the scenario. They were expressly forbidden to attempt to answer questions or respond to comments in any way other than to repeat information contained in the written scenario. Furthermore, interviewers were trained to read the scenario exactly as it was written. In this way, the information presented to each person interviewed was exactly the same. A copy of the information packet given to each respondent when the scenario was presented concludes this chapter.

AGD 533084

FAIRBANKS PETROCHEMICAL STUDY

Interview Packet

SECTION B

PETROCHEMICAL DEVELOPMENT DESCRIPTION

1 We have found that not everyone expects petrochemical development to cause the same changes in the Fairbanks area. Some people believe the petrochemical plant would be very small and others feel it would be very large, for example. For this reason, it would be unfair of us to ask everyone simply if they favor petrochemical development. One person may favor petrochemical development because he thinks it will create many jobs and little air pollution. Another person may oppose petrochemical development because he thinks it will only employ outsiders and will result in poor air quality. Many more people may have no opinion because they don't know what to expect.

2 As a part of this study, we have asked several experts in the field of energy development to give us a description of the general type of petrochemical industry which could possibly locate in the Fairbanks area. The description includes how many people might be employed, what kinds of pollution might be produced and how much taxable property might be added in the Borough. I would like to take a few minutes to read the short description to you before proceeding with this interview.

3 As you know, the Prudhoe Bay field consists not only of the crude oil that is being transported in the trans-Alaska oil pipeline but also natural gas. Current plans call for all or a portion of the natural gas to be transported by pipeline down the oil pipeline corridor to Fairbanks and then along the Alaska highway through Canada to the lower 48 states.

GAS PIPELINE

4 The State of Alaska owns a portion of the natural gas that is to be transported; it is referred to as State royalty gas. The State or even one of the private companies owning the gas may choose to sell some of the gas inside Alaska. Gas sold in Alaska might be used directly as fuel for homes and industry; most likely, however, it would be sold to a company which would make new products out of the gas. A petrochemical plant is basically a plant which uses natural gas or crude oil to make all sorts of new chemical products.

PETRO-CHEMICAL PLANT

AGO 533085

In the case of Fairbanks, the type of petrochemical plant we are talking about would use only natural gas, not the crude oil.

5 A petrochemical plant is expensive to build anywhere, but in Fairbanks it would cost between 50 and 100 percent more to build. The transportation costs of shipping the

ECONOMIC FACTORS

products from Fairbanks to world markets would also be very high. The high construction and transportation costs for a Fairbanks plant make it uncertain if the plant could deliver its products to world markets at a price that is the same or lower than that of plants located elsewhere. In other words, it may not make economic sense to build a petrochemical plant in the Fairbanks area. On the other hand, if a plant were built in Alaska, Fairbanks would be one logical location.

6 For what we are talking about today, we don't have to worry about whether a petrochemical plant can be built in Fairbanks. We want to know what your opinions are about a petrochemical plant <u>if</u> it is built in the Fairbanks area.

7 How do the experts think a petrochemical plant would change Fairbanks anyway? Well, naturally, the experts don't all agree and there are many possible types of plants they can choose from. However, we did get several of them to agree on what they believe is the general type of plant that could be built in Fairbanks.

8 Here is a diagram which shows you what's involved. Leaving Prudhoe are two lines, oil and gas. Both lines pass

METHANE

through the Fairbanks North Star Borough. Inside the Borough, State royalty gas is taken from the gas pipeline and separated into methane, the lightest gas, and a mixture of ethane and propane. From the separator plant, the methane is used primarily to make methanol which can be used as a fuel. The methanol and other methane-based products are shipped out of Fairbanks in a third pipeline and/or in special cars on the Alaska railroad. Just to give you an idea of scale, the methanol produced would more than double the supply in the United States.

9 The separated ethane, and a little propane, is converted

ETHANE

primarily to ethylene which in turn is used to make ethanol, or polyethylene pellets and a mixture of other products. Neither the ethane or the ethane would be used to produce any finished chemical products such as paints, pantyhose

PRODUCTS

or pharmaceuticals. While some products like ethylene glycol, the basic ingredient in anti-freeze, would be produced, our experts tell us that there is not much chance of their being marketed locally; and if they were, the price

would not differ greatly from what you pay now. The entire plant and surrounding lands might occupy one square mile.

10 Now on to what the petrochemical plant would mean to you, a Fairbanks resident. The plant would take about three years to construct, using an average of some 1,500 workers with a peak employment of perhaps twice that. Put another way, the local construction employment would be roughly two-thirds of the local employment during the construction of the oil pipeline. The first year of construction would probably involve local contractors and labor. Later stages of construction would require special skills not common in Fairbanks.

CONSTRUCTION

11 I mentioned earlier that the plant would be expensive to build. That means that if it is built the plant will add a great deal to the total amount of taxable property in the North Star Borough. In fact, the plant would be worth between about 810 and 860 million dollars. That would represent about 40 percent of the value of all the property (including your home and everyone else's) in the Borough. If the plant paid property taxes at the current tax rate, it would pay 4 million a year to the Borough and increase total Borough revenues by about 15 percent.

TAXABLE PROPERTY

12 To recap our description so far, the plant would process the State royalty gas and ship the products by pipeline to Haines or the Cook Inlet. Few, if any, products would be available locally. The construction of the plant would require about two-thirds the number of workers locally as required by the construction of the oil pipeline. The plant itself would increase the amount of taxable Borough property by 40 percent.

RECAP

13 Besides local products, construction jobs, and tax revenues, we need to know something about permament jobs created by the petrochemical plant. About 600 persons would work at the plant. Fifty of these jobs would be related to the overall management of the plant. The remaining 550 would be divided into shifts because the plant would have to operate 24 hours a day, year round. The plant jobs would either be filled by new residents or by existing Fairbanks residents who learn the necessary skills.

PERMANENT JOBS

14 The plant would also indirectly result in roughly 100 new jobs ranging from sales clerks to hairdressers, depending on what new demands are placed on the community. All in all, the new jobs at the plant and in the community might bring 1,200 people to Fairbanks. The 1,200 represents about a 2 percent increase in population and would add their share of cars, housing, and ice fog and spend their share of dollars in the community.

INDIRECT JOBS

POPULATION

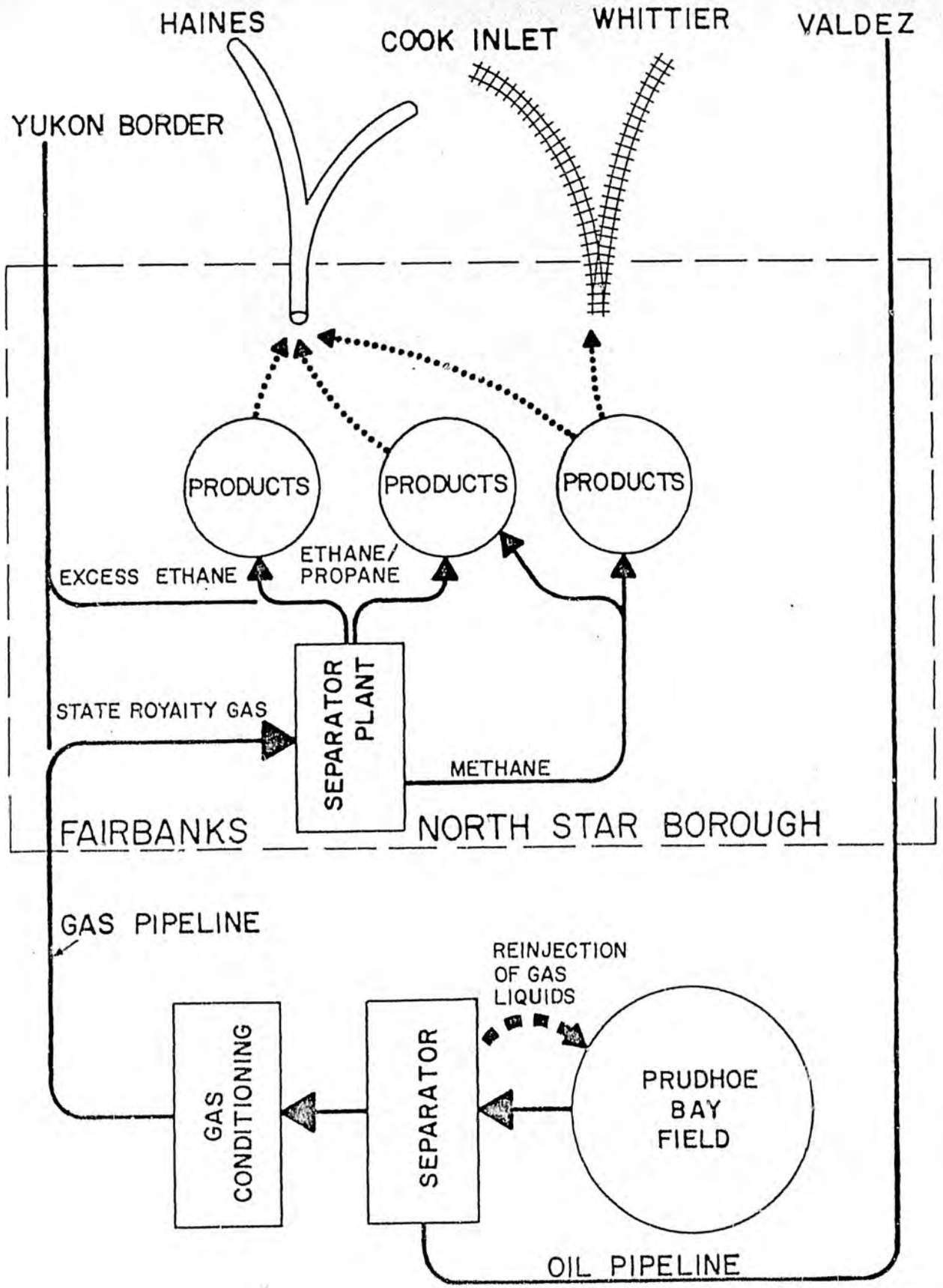
AGO 533087

15 The last part of our description concerns the effect of the plant on our air and water. The plant will use water, but probably they would use air rather than water

ENVIRONMENT where they need to cool a chemical process. As a result the plant would not use tremendous amounts of water or release hot water into nearby rivers. Gas-based petrochemical plants like the one we're talking about do not give off smelly or toxic fumes that oil-based petrochemical plants do. Gas-based plants do produce water vapor which could becore ice fog in the winter. The water vapor problem and other factors make it desirable to locate the plant on higher ground, 600 feet or more above the urban area. The water vapor would then be released above the layer of air we breathe and drive around in. Since the higher layers of air do not mix with the lower layers on cold days, any ice fog produced by the plant would not be added to the ice fog layer in the urban area.

AGO 533088

FIGURE 2-2



AGO 533089

FIGURE 2-3

EFFECTS OF PETROCHEMICAL DEVELOPMENT

1. CONSTRUCTION
3 YEARS
1500 WORKERS

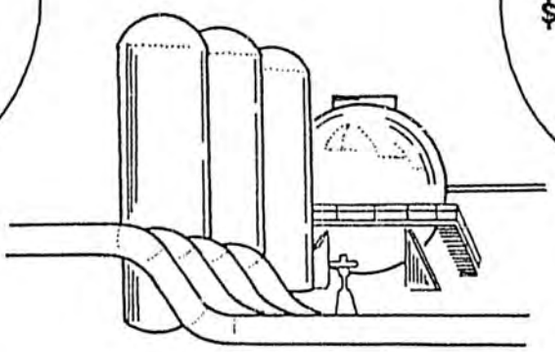
2. TAXABLE PROPERTY
$ 810 - 860 MILLION
$ 4 MILLION BOROUGH REVENUES

3. PRODUCTS
NONE LOCALLY AVAILABLE

4. EMPLOYMENT
600 PERSONS
100 INDIRECT JOBS

5. POPULATION INCREASE
1200 PERSONS
2% INCREASE IN POPULATION

6. ENVIROMENT
NO SMELL
NO TOXIC FUMES
ICE FOG ABOVE NORMAL LAYER



State of Alaska

AGO 533091 +

LAZARD FRÈRES & CO.
ONE ROCKEFELLER PLAZA
NEW YORK, N.Y. 10020

CABLE ADDRESS "LAZARD NEW YORK"
TELEPHONE (212) 489-6600

NEW YORK

November 20, 1979

The Honorable Avram Gross
Attorney General
State of Alaska
Juneau, Alaska

Dear General Gross:

This letter report will summarize our finds and recommendations on the issue of State financial support and participation in the proposed Alaskan Gas Pipeline.

Introduction

A discussion of State participation in the financing of the Alaskan Natural Gas Transportation System (ANGTS) should be first predicated on the conviction that a commitment of State resources to the project is desirable for the State of Alaska and its citizens. We believe there are solid demonstrable benefits to the State and its citizens to be derived from State participation. This opinion is not based on the proposition that without State participation the project will fail. Rather, it is based on the conviction that State financial participation will accelerate the project and that the State can and should achieve special leverage with respect to its own interests.

1. Jobs

An acceleration of the project creates jobs and economic activity now rather than later. To the current residents of Alaska today, jobs and economic activity have a concrete meaning.

2. Government Revenues (Royalty, severance tax, ad valorem taxes)

Based on a production level of 2 billion cubic feet of gas per day, governmental revenues should approach $500 million annually to the State by the time the line is open. On a discounted, present worth basis, dollars shifted from latter years to earlier years become more valuable. A delay of one year means permanently foregoing the largest part of the value of $500 million. This represents more than $1,200 per person in the State of Alaska.

3. Leverage at the Bargaining Table

The State will want to be a full fledged, participant in the resolution of a number of pipeline-related issues, including but not limited to the capture of the liquids stream to insure its highest and best use. By taking a constructive financial role, the State can arrive at the bargaining table in an advantageous manner. Without State financial participation, the State will still have a position, but a position whose strength depends largely upon regulation, controls and a certain negativism, which could have unfortunate side effects mentioned directly below.

4. Business Climate

The pipeline project is of such magnitude that the business community cannot avoid focusing on it and the State's role. Actions by the State will be scrutinized and conclusions,

fortunately or unfortunately, magnified. At a time when State governments have all become extremely competitive relative to attracting jobs, it is important that the State of Alaska be conscious that its actions on the pipeline may affect the business community's perception of the overall business climate in Alaska. A policy which demonstrates a constructive policy toward business activity may be essential to a long term policy to broaden the economic base of the State.

5. The United States Congress

Historically, the United States Congress has played a larger role in the affairs of Alaska than in most other States. Being an active participant in this major project gives the State and its representatives in the Congress an opportunity to make friends and alliances which in the long run can pay dividends in areas entirely distinct from the pipeline itself. An inward-turning, perhaps isolationist policy, may not give the State it's maximum leverage in many other areas of State concern and interest.

For the reasons listed above, we conclude that it is in the best interests of the State to move the ANGTS project forward.

Forms of State Participation

This letter report will now address the way in which the State can most effectively move the project forward and simultaneously

further the special interests of the State. Specifically, we will review four possible methods of State participation. We will recommend as a preferred approach State ownership in its entirety of the gas conditioning plant.

1. State Ownership of Gas Conditioning Plant

The first alternative and, in our opinion, the preferred alternative, is the ownership by the State of the gas conditioning plant (estimated cost of $2.8 billion). Gas conditioning is essential to the operation of the ANGTS project, and, yet, is a discrete project, which can be separately financed and operated. The risks of construction and ownership are modest. With respect to construction risks, a gas conditioning plant is not an item in the leading edge of technology; it is well within the normal range of construction technology. With respect to ownership risks, contractual arrangement can be made with producers and shippers so as to minimize the economic risks. These contractual arrangements would be in the form of take-or-pay contracts, or tolling fees which would guarantee operating costs, debt service and an agreed upon rate of return to the State. Under the most likely negotiations, the rate of return on the equity investment should match the pipeline's overall return (17 1/2%). The special economic benefit to the State is that the ownership of the plant will give the State considerable flexibility in capturing the value-added to liquids, and insuring its best use.

By carving out a special, distinct portion of the project for the State, the State will have greater negotiating leverage with respect to the pipeline than being a minority partner in the overall project.

As part of the arrangements with the producers, the State will negotiate an Option Agreement for five years for the purchase of a major portion of the liquids from the plant. This Option Agreement will enable the State to stimulate further economic development as circumstances permit.

From the point of view of the producers and shippers, the ownership by the State of the gas conditioning plant would relieve the overall pipeline project of considerable equity and debt financing, thereby releasing funds for the balance of the project.

The financing of the gas conditioning plant would not be a major problem. The plant would be financed by a maximum of 25% in equity and 75% in the form of non-recourse, tax-exempt debt. By non-recourse we mean the State would not be liable for the debt. The project itself, and contracts with producers and shippers would support the debt.

By shifting plant ownership to State hands, tax-exempt financing[1] would become likely. In addition, State ownership would mean that the

---

(1) We would expect that Congressional approval would be required to satisfy the IRS in a project of this size.

plant would pay no income taxes. The change to tax-exempt status would substantially reduce conditioning costs. Inasmuch as conditioning costs are a major stumbling block in the financial plan of the producers and shippers, a reduction in such costs would be a welcome move by all parties.

It should be noted that the shift of ownership to State hands does not require in itself, that the conditioning costs be paid by producer or shipper, or by a combination of both. The resolution of this issue is separate from the issue of ownership. Similarly, the ownership of the plant by the State does not, in itself, resolve the issue of where the plant will be located (Prudhoe or Fairbanks). This, again, is a separate issue. However, the State's ownership position may result in a greater likelihood of compromise on these issues.

2. Other Alternatives for State Participation

a. The issuance of non-recourse, tax-exempt, revenue bonds, by the newly-created Alaska Gas Pipeline Financing Authority.

In June 1978, the Alaska State Legislature authorized up to $1 billion in non-recourse revenue bond financing to be issued through a newly-created Alaska Gas Pipeline Financing Authority. The main purpose of this alternative was to tap new sources of financing the tax-exempt bond market.

The issuance of the proposed $1 billion, non-recourse, tax-exempt, revenue bonds is, in our opinion, entirely feasible and will

not adversely affect the credit of the State. This form of participation is of low risk to the State. This alternative is primarily a demonstration of the State's good will which is an important ingredient in setting the proper climate conducive to moving the project forward. This alternative does not, however, provide any special benefits to the State other than in helping to move the overall project forward, nor does it create any particular leverage for the State except that which is provided by general good will. This alternative is a minimal commitment and a minimal risk.

A change in the Federal tax code would be necessary to effect this alternative.

b. Insurance Fund

A third alternative for financial participation in the overall project would be to create an insurance fund jointly with the Federal government to cover part of the costs of possible overrun. Inasmuch as the overrun problem is the key financial problem for the private sector, the State might consider establishing an insurance fund jointly with the Federal government to give greater assurance as to project completion. The joint insurance fund would come into play only after the normal project contingency fund was exhausted. The joint insurance fund would purchase senior, secured bonds of the pipeline at market interest rates with relatively rapid amortization. The joint insurance would not require equal contributions of the State and the Federal government. It would be expected that the Federal government's share

of the insurance fund might be three or four times that of the State. The insurance fund would receive a commitment fee from the insured until completion.

As an illustration, there might be created a special Alaska Gas Pipeline Insurance Fund in the amount of $2 billion, of which the State of Alaska's share would be $500 million. The Insurance Fund would be tapped only:

a) when the original financing, plus a 50% contingency reserve, is exhausted,

b) upon the further contribution by the private participants of 25% of additional overruns.

Using an Insurance Fund as a method of financial participation is relatively low risk for the State. Having the Federal government as a partner is an advantage. Such a contingent commitment is well within the financial capacity of the State. A Federal government insurance program has a great number of precedents, and has served critical functions in housing, banking and other projects which depend heavily on the private sector.

c. State Minority Participation in the Pipeline Itself

It has frequently been suggested that the State of Alaska participate directly in the financing of the overall pipeline project by purchasing a minority interest in the equity and/or debt of the pipeline itself. At times it has been suggested that because the State receives a 1/8th royalty share that it should purchase a 1/8th

position in the pipeline. A 1/8th participation in the ownership and/or financing of the pipeline would mean that the State would assume the same risks and rewards as the producers and/or shippers. This alternative would not give the State any special benefit in return for a very large commitment. From the point of view of the producers and shippers, this 1/8th participation is not particularly needed and does not address the thorny question of overruns, which question will continue to plague the financibility of the project. Moreover, a 1/8th minority interest does not give the State very much leverage to achieve its particular ends in policy making and direction of ANGTS, nor in future economic development.

Summary

All four alternatives described above have merit because they demonstrate the State's good will toward the project, with favorable implications for the business climate in Alaska. All four approaches move the project forward. However, all the alternatives do not necessarily carry the same degree of risk or rewards for the State.

To summarize each alternative, the first alternative, the one we favor and recommend, the ownership by the State of the Gas Conditioning Plant, involves a substantial commitment by the State, but a low risk one. This alternative generates considerable economic benefits as well as special long term benefits for the State of Alaska and its citizens. The second alternative, that of issuance of non-recourse,

tax-exempt revenue bonds, represents a minimal commitment and a minimal risk. The third alternative, that of a joint State Federal insurance fund, is relatively low risk and moves the project ahead importantly. However, it does not generate special benefits for the State of Alaska. The fourth alternative, that of a 1/8th participation in the overall project, is a major commitment with considerable risks and rather modest special benefits.

Next Step

In order to move a project of this magnitude ahead, it is strongly urged that an organization be established with Legislative authority to (a) prepare detailed feasibility studies, (b) negotiate necessary contracts with the producers and shippers, and (c) negotiate with the Federal government for the necessary approvals. The objective would be to prepare a plan and budget which can be submitted to the State Legislature for their approval.

It is particularly necessary to consolidate the State's effort into a small organization in order to negotiate seriously with producers and shippers. Producers and shippers will not seriously negotiate unless there is clear authority for such negotiations and a positive expression of intent by the Legislature.

Without attempting to impose any particular organization, it is suggested that a special Authority be established, an Executive Di-

rector and a small Board consisting of members of the Legislative houses and the Executive Branch be appointed. The Authority would be asked to submit to the State Legislature the final proposal for a commitment of State funds and borrowing authority by no later than January 5, 1981. Obviously, such commitment would be conditioned on the entire ANGTS project proceeding on a satisfactory basis.

Only minimal funds (estimated at $250,000) would be needed to bring the gas conditioning plant plan to the final Legislature approval stage. When the ANGTS project goes forward, the Authority could be expanded.

Attached is a report prepared by Purvin & Gertz addressing some of the technical issues involved in the construction and ownership of a gas conditioning plant.

Very truly yours,

Lazard Frères & Co.

PAL:g

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA, CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES
REP. BILL MILES, CO-CHAIRMAN
REP. CHAT CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR
EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACKMAN

POUCH V
JUNEAU, ALASKA 99811
(907) 465-3779
3/17/80

To: Members of the Joint Gas Pipeline Committee
From: Mary Halloran, MH Research Analyst

Re: Gas Conditioning Costs and Implications for State Revenues

At one point during the national negotiations over the Northwest gas pipeline project financing, it was suggested that the producers and/or the State might be penalized for not participating in project financing through federal manipulation of the gas wellhead price or the conditioning costs. The attached paper by Alexander Hoke of the House Research Agency analyzes the potential penalities to the State from different conditioning costs scenarios. The range between the "best" case and the "worst" case from the State's perspective is $3.9 billion.

The analysis is based on 53¢/Mcf for all conditioning costs (24.9¢/Mcf for operating costs and 28.1¢/Mcf for capital costs), and a wellhead price of $1.95/Mcf (1980 value). The field life is estimated to be forty years.

The cases and results are as follows:
Case 1. State and producers bear all conditioning costs, operating and capital, but not through a reduction in the wellhead value. No conditioning costs are passed through to consumers. State revenue = $16.6 billion.
Case 2. State passes through all conditioning costs; but producers bear all conditioning costs, but not through a reduction in wellhead value. State revenue = $18.8 billion.
Case 3. State bears all conditioning costs, but not through a reduction in wellhead value; producers pass through operating costs of conditioning, and bear capital costs but not through a reduction in wellhead value. State revenue = $17.2 billion.
Case 4. State bears all conditioning costs, but not through a reduction in wellhead value; producers pass through all conditioning costs. State revenue = $17.3 billion.
Case 5. All conditioning costs, both capital and operating, are deducted from the wellhead value for royalty purposes. State revenue = $15.7 billion.
Case 6. Only operating conditioning costs are deducted from the wellhead value for royalty and severance tax purposes. State revenue = $15.1 billion.
Case 7. All conditioning costs, both capital and operating, are deducted from the wellhead value for royalty and severance tax purposes. State revenue = $14.9 billion.

AGO 533103

HOUSE RESEARCH AGENCY
Pouch Y - State Capitol
Juneau, Alaska 99811
465-3991

MEMORANDUM March 10, 1980

TO: Representative Miles

FROM: Alexander Hoke Alexander Hoke

RE: Gas Conditioning Costs
Research Request No. 29

The following analysis is offered in response to your question regarding potential "penalties" to the State involving gas conditioning costs if the State does not participate in financing the Alaska Highway Gas Pipeline project. The Federal Energy Regulatory Commission's interpretation of the 1978 Natural Gas Policy Act lays the burden of gas conditioning costs on the producers of gas, which, in effect, precludes the State from being "penalized" with regard to conditioning costs. Our intent in this memorandum is to avoid speculating on the potential with which a "penalty" scenario may come to fruition, but rather direct our efforts to an analysis of the financial implications of a given "penalty" scenario should it occur.

Should the State of Alaska elect not to participate in gas pipeline financing, there appear to be two means by which the State could become the object of a "penalty" by the investors on the pipeline for its failure to bear a portion of the financial risk. The word "penalty" is used loosely here in reference to any disparity in treatment of the State relative to gas producers who participate in pipeline financing. Both "penalties" take the form of a differentiation in the wellhead price of gas produced at the North Slope.

Conditioning Cost Pass-Through for Pipeline Investors

The first means [and the most likely given the timbre of recent Federal Energy Regulatory Commission (FERC) ruling appeals by gas producers and potential sponsors of the Alaska Gas Pipeline] requires that FERC grant a financial hardship ruling which, in effect, permits those who participate in the financial risks of the pipeline to pass some or all of their share of the gas conditioning costs through to the gas purchasers. On the other hand, if the State chose not to participate financially in the pipeline, its share of conditioning costs would likely not be permitted to pass through to gas purchasers, resulting in an effectively lower

wellhead value for the State relative to that for pipeline investors. For example, gas conditioning capital costs amortized over 30-year terms average 28.1¢ per MCF. The operating component of conditioning costs over the productive life of the field average about 24.9¢ per MCF. If sponsors of the gas pipeline were permitted to pass this total conditioning cost of 53¢ per MCF through to the gas purchasers, their effective wellhead price would be increased from $1.95/MCF to $2.48/MCF. The State, on the other hand, would not be permitted to pass through the conditioning costs, and consequently, its wellhead value for royalty and severance tax purposes would remain at $1.95/MCF (gas price ceiling fixed by 1978 Natural Gas Policy Act in 1980 dollars).

Conditioning Cost Deduction from Wellhead Price

The second method for differentiating the wellhead gas price on the basis of non-participation in gas pipeline financing involves a deduction of some, or all of the cost of gas conditioning from the wellhead price ceiling of $1.95/MCF. In this scenario, the State of Alaska, as a consequence of non-participation in gas pipeline financing, would be "penalized" by deducting up to 24.9¢/MCF for the operating component of conditioning costs (leaving a wellhead price of $1.70/MCF), or by deducting up to 28.1¢/MCF for capital conditioning costs (resulting in a $1.67/MCF wellhead price), or by deducting all gas conditioning costs (which results in an effective wellhead price of $1.42/MCF).

The "No-Penalty" Scenarios

Scenario number 1 of the attached table assumes that conditioning costs are neither deducted from the wellhead price of gas, nor permitted to be passed through to gas purchasers as a special federal allowance to offset the burdensome capital investment risks borne by those who participate in pipeline financing. The wellhead price of gas ($1.95) is the 1980-dollar value of the price ceiling fixed in the 1978 Natural Gas Policy Act. The 35.5% figure in the fifth column represents the fraction of total industry net cash flow on the attached computer run #1, constituted by the gas net cash flow component [39,706 ÷ (39,706 + 72,130) = 35.5%]. This percentage is used to calculate the figure for State income tax for gas production from the total State income tax listed on the computer printout.

In the last column, industry net cash flow from gas production is given as a comparitive measure of industry profits relative to total State revenue in the adjacent column. The total State revenue in this "no-penalty" scenario run is $16.6 billion.

Scenario #2 is shown on the attached table to indicate the level of increase in total revenue to the State that would accrue if the State participated in pipeline financing, and if FERC ruled that those bearing financial risk in the pipeline were permitted to pass conditioning costs (operating and capital) through to the gas purchasers. State revenues of $18.8 billion under this scenario significantly exceed the $16.6 billion revenues projected in the "no-penalty" scenario #1.

The "Penalty" Scenarios

Conditioning Cost Pass-Through:

Scenario #3 shows the effect of a pass-through of the operating costs of conditioning to gas purchasers allowed for gas producers only. Total State revenues = $17.2 billion.

Scenario #4 demonstrates the impact of permitting gas producers only the transfer of conditioning costs (operating and capital) to gas purchasers--compare to Scenario #2. Total State revenues = $17.3 billion.

Conditioning Cost Deduction from Wellhead Gas Price:

Scenario #5 shows the impact of deducting all conditioning costs (capital and operating) from the wellhead price of gas ($1.95/MCF) for royalty purposes only. Total State revenue = $15.7 billion.

Scenario #6 demonstrates the effect of deducting only the operating costs of conditioning from the wellhead price of gas for royalty and severance tax purposes. Total State revenue = $15.1 billion.

Scenario #7 represents the situation in which all conditioning costs (operating and capital) are deducted from the wellhead gas price for royalty and severance tax purposes. Total State revenue = $14.9 billion.

The Monetary Effect of Conditioning Cost Penalties

The most immediately apparent observation when comparing conditioning cost "penalty" scenarios 3 through 7 to the "no-penalty" scenario #1 are the differences in total State revenue. Scenarios 3 and 4 involving conditioning cost pass-through to gas purchasers result in higher revenues to the State than the $16.6 billion in the "no-penalty" scenario #1. This is primarily due to the increased State income tax revenue on higher profits earned by the producers when the conditioning costs are assumed by the purchasers of gas. On the other hand, scenarios 5, 6 and 7 have lower totals for State revenue than the "no-penalty" scenario #1, because deductions of gas conditioning costs from the wellhead price of gas directly affects royalty and severance tax revenue.

Conditioning Cost Pass-Through to Gas Purchasers:

Scenario #4 demonstrates the effect of an allowed pass-through of conditioning costs to gas purchasers by the gas producers (effectively raising their wellhead gas price to $2.48/MCF) while dissallowing the pass-through for the State of Alaska (which leaves the State's wellhead value at $1.95/MCF). Scenario #4 shows a total State revenue of $17.3 billion indicating a "penalty" from scenario #2 of $1.48 billion (18.779 - 17.302 = 1.48). Curiously, however, the total State revenue under this "penalty" situation is higher than the "no-penalty" scenario #1. In other words, even though the State may be "penalized" by not receiving the conditioning cost pass-through approval from FERC as a result of non-participation in gas pipeline financing, the State's total revenues would increase primarily due to higher income tax revenue on the producers' increased profits.

Conditioning Cost Deductions from Wellhead Gas Prices:

Scenarios 5, 6 and 7 show that total State revenues are significantly lower (than scenario #1) when operating and/or capital conditioning costs are deducted from the wellhead gas price of $1.95/MCF. In the worst case (scenario #7) average operating costs of 24.9¢/MCF and average capital costs of 28.[illegible]¢/MCF deducted from the $1.95/MCF wellhead price results in an effective wellhead price for State tax purposes of $1.42/MCF. When this deduction is applicable to royalties and severance taxes, the total State revenue is reduced to $14.9 billion compared to $16.6 billion when no deductions are made. The magnitude of the decrease in revenues from the "no-penalty" scenario #1 are somewhat attenuated when only the operating costs of conditioning are deducted from the wellhead price (scenario #6--total revenue = $15.1 billion), or when conditioning costs are deducted from the wellhead price for royalty purposes only (scenario #5--total revenue = $15.7 billion).

While the conditioning cost "penalties" described in scenarios 5, 6, and 7 are the most severe of those shown on the attached table, there is ample reason to suggest that the likelihood of their occurrance is remote. The Federal Energy Regulatory Commission Order #45, adopted August 24, 1979, addresses conditioning costs as the responsibility and burden of the producers of gas. Consequently, the fixed price ceiling set in the 1978 Natural Gas Policy Act could be defined as net of conditioning costs. In other words, the present price ceiling already excludes conditioning costs and further deductions from the ceiling price for conditioning cannot be justifed. Therefore, scenarios 5, 6 and 7 would seem inplausible short of a countermanding rule from FERC on conditioning costs.

Methodology

Calculations made in preparing this analysis revolve around the use of the Eppenbach Producer Benefits computer model. As numerous assumptions have been made about production and price scheduling, debt financing (term, interest rates, amortization mode, etc.) federal tax rates, the proportion and timing of capital investments and many other environmental parameters of the model, discretionary interpretation of the precision of projected revenues is suggested. However, the relative magnitude of the projected State revenues are of greater policy significance, and we believe that the projections shown on the attached table fairly represent an accurate comparison of the relationship of one "penalty" scenario to another.

prepared by:
House Research Agenc

ALASKA REVENUE FROM NORTH SLOPE GAS PRODUCTION
(Millions of Dollars)

Conditioning Cost Penalty Scenario	Effective Wellhead Gas Price (per MCF)[1]	Royalty	Severance	Property Tax	Gas % of Total Net Cash Flow[2]	State Income Tax[3]	Total State Revenue	Gas Industr Net Cash Fl
1. Control Scenario no deviation	$1.95	$7,206	$5,044	$389	35.5%	$3,971	$16,610	$25,004
2. 30-year pass-through for State and producers of operating & capital costs	2.48	8,127	5,689	389	38.9%	4,574	18,779	28,897
3. 30-year pass-through of operating costs for producers only	1.95	7,206	5,044	389	38.6%	4,523	17,162	28,566
4. 30-year pass-through of operating & capital costs for producers only	1.95	7,206	5,044	389	39.4%	4,663	17,302	29,479
5. Operating & capital costs deducted (royalty)	1.42	6,104	5,154	389	36.3%	4,099	15,746	25,829
6. Operating costs deducted (royalty & severance)	1.70	6,285	4,399	389	36.0%	4,062	15,135	25,586
7. Operating & capital costs deducted (royalty & severance)	1.42	6,104	4,273	389	36.3%	4,099	14,865	25,829

[1]Effective wellhead price of gas for state tax purposes: 1980-dollar equivalent of the 1978 Natural Gas Policy Act gas price ceiling adjusted up or down by the following average conditioning costs: operating = 24.9¢/MCF capital = 28.1¢/MCF

[2]Gas component (percentage) of combined oil and gas net cash flows from attached computer runs.

[3]Multiply percentage in previous column times total state income tax from attached computer runs.

[4]Industry Net Gas Cash Flow from attached computer runs minus State and Federal Income tax multiplied by Gas % in previous column.

AGO 533109

ALASKA STATE REVENUES
(MILLIONS OF DOLLARS)

YEAR	OIL PROD RATE MBL/DAY	OIL ROYALTY PAYMENT	OIL SEVERANCE TAX	OIL PROPERTY TAX	OIL CONSERV. TAX	OIL TOTAL	GAS PROD RATE MMCF/DAY	GAS ROYALTY PAYMENT	GAS SEVERANCE TAX	GAS PROPERTY TAX	GAS TOTAL	STATE INCOME TAX	TOTAL STATE RETURN
1977	1.050	191.6	187.7	36.0	0.4	415.9	0.000	0.0	0.0	0.0	0.0	0.0	415.9
1978	1.425	390.0	382.2	37.9	0.6	810.9	0.000	0.0	0.0	0.0	0.0	197.2	1,008.2
1979	1.589	633.0	603.1	40.0	0.6	1,276.8	0.000	0.0	0.0	0.0	0.0	333.4	1,610.2
1980	1.509	950.1	750.8	41.7	0.6	1,760.4	0.000	0.0	0.0	0.0	0.0	528.6	2,289.1
1981	1.500	977.2	755.2	45.2	0.6	1,778.5	0.000	0.0	0.0	0.0	0.0	535.3	2,313.8
1982	1.479	936.8	750.1	50.1	0.6	1,737.8	0.000	0.0	0.0	3.0	3.0	539.5	2,340.4
1983	1.500	1,016.7	744.4	57.3	0.6	1,819.2	0.000	0.0	0.0	7.5	7.5	543.6	2,370.5
1984	1.500	1,077.1	737.5	64.1	0.6	1,839.5	0.000	0.0	0.0	12.1	12.1	547.3	2,399.0
1985	1.500	1,057.8	734.5	70.4	0.6	1,863.5	2.000	177.9	124.5	17.6	320.1	674.5	2,858.3
1986	1.300	905.1	649.3	68.7	0.5	1,653.8	2.000	177.9	124.5	17.3	319.8	601.6	2,575.3
1987	1.150	803.7	581.7	66.8	0.5	1,452.9	2.000	177.9	124.5	17.0	319.5	549.6	2,362.1
1988	1.020	748.3	512.7	62.9	0.4	1,324.1	2.000	177.9	124.5	16.5	319.0	495.3	2,138.6
1989	0.750	580.1	390.6	59.0	0.3	1,030.1	2.000	177.9	124.5	16.1	318.6	398.4	1,747.2
1990	0.560	451.6	299.3	55.0	0.2	806.3	2.000	177.9	124.5	15.6	318.1	324.7	1,449.2
1991	0.420	333.5	216.6	51.1	0.1	601.5	2.000	177.9	124.5	15.2	317.7	256.9	1,176.2
1992	0.400	324.0	205.0	47.2	0.1	576.4	2.000	177.9	124.5	14.7	317.2	253.2	1,146.9
1993	0.350	289.2	176.3	43.2	0.1	508.9	2.000	177.9	124.5	14.3	316.8	234.5	1,060.3
1994	0.330	278.1	154.3	39.3	0.1	472.0	2.000	177.9	124.5	13.8	316.3	230.7	1,019.1
1995	0.320	275.0	129.0	35.4	0.1	439.6	2.000	177.9	124.5	13.4	315.9	232.5	988.1
1996	0.250	219.2	71.9	31.4	0.1	322.7	2.000	177.9	124.5	12.9	315.4	202.7	841.0
1997	0.230	205.7	0.0	27.5	0.1	233.3	2.000	177.9	124.5	12.5	315.0	203.4	751.8
1998	0.200	182.4	0.0	23.6	0.0	206.1	2.000	177.9	124.5	12.0	314.5	191.1	711.8
1999	0.170	158.1	0.0	19.6	0.0	177.9	2.000	177.9	124.5	11.6	314.1	178.0	670.1
2000	0.150	142.3	0.0	15.7	0.0	158.1	2.000	177.9	124.5	11.2	313.6	171.3	643.2
2001	0.130	125.8	0.0	11.8	0.0	137.7	2.000	177.9	124.5	10.7	313.2	165.5	616.5
2002	0.120	118.4	0.0	7.8	0.0	126.4	2.000	177.9	124.5	10.3	312.8	167.1	606.3
2003	0.120	100.7	0.0	0.0	0.0	100.7	2.000	177.9	124.5	9.8	312.3	162.2	575.4
2004	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	9.4	311.9	102.8	414.7
2005	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.9	311.4	104.1	415.6
2006	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.5	311.0	105.5	416.5
2007	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.0	310.5	105.5	416.1
2008	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	7.6	310.1	105.5	415.7
2009	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	7.1	309.6	105.6	415.3
2010	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	6.7	309.2	105.6	414.8
2011	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	6.2	308.7	105.7	414.4
2012	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	5.8	308.3	105.7	414.0
2013	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	5.3	307.8	105.8	413.6
2014	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.9	307.4	105.8	413.2
2015	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.4	306.9	105.8	412.8
2016	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.0	306.5	105.9	412.4
2017	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	3.5	306.0	105.9	412.0
2018	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	3.1	305.6	106.0	411.6
2019	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	2.6	305.1	106.0	411.2
2020	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	2.2	304.7	106.0	410.8
2021	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	1.7	304.2	106.1	410.4
2022	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	1.3	303.8	106.1	410.0
2023	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.8	303.3	106.2	409.6
2024	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.4	302.9	106.2	409.2
2025	0.000	0.0	0.0	0.0	0.0	0.0	1.000	88.9	62.2	0.0	151.2	48.4	199.7
2026	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0
	7,641T	13,570	9,042	1,109	9	23,73?	89,565T	7,206	5,044	389	12,640	11,186	47,559

CUMULATIVE TOTALS

AGO 533110

INDUSTRY CASH FLOWS
(MILLIONS OF DOLLARS)

YEAR 1-50	* * * * * * OIL PRODUCTION * * * * * * WELLHEAD PRICE/BBL	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET OIL CASH FLOW	* * * * * * GAS PRODUCTION * * * * * * WELLHEAD PRICE/MCF	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET GAS CASH FLOW	ST. INC. TAX	FED. INC. TAX	TOTAL NET CASH FLOW
1	4.00	1533.0	415.9	103.0	122.6	891.4	1.95	0.0	0.0	26.0	0.0	-26.0	0.0	259.6	605.7
2	6.00	3120.7	810.9	140.0	161.9	2007.8	1.95	0.0	0.0	33.0	0.0	-33.0	197.2	533.2	1244.3
3	9.25	5084.3	1276.8	156.0	187.4	3444.0	1.95	0.0	0.0	32.0	0.0	-32.0	333.4	923.6	2155.0
4	14.00	7665.0	1760.4	163.0	290.6	5450.9	1.95	0.0	0.0	36.0	0.0	-36.0	528.6	1465.8	3420.3
5	14.28	7818.3	1778.5	171.0	369.0	5499.7	1.95	0.0	0.0	41.0	92.6	-133.6	535.3	1449.2	3381.5
6	14.56	7974.6	1797.8	173.0	511.9	5491.8	1.95	0.0	3.0	48.0	148.5	-199.6	539.5	1425.8	3326.8
7	14.85	8134.1	1819.2	174.0	590.3	5550.4	1.95	0.0	7.5	54.0	172.8	-234.3	543.6	1431.7	3340.7
8	15.15	8296.8	1839.5	178.0	668.8	5610.5	1.95	0.0	12.1	60.0	235.1	-307.2	547.3	1426.7	3329.1
9	15.45	8462.7	1863.5	230.0	462.7	5906.4	1.95	1548.0	320.1	192.0	104.9	930.9	674.5	1848.8	4313.9
10	15.76	7481.0	1653.8	210.0	476.3	5140.8	1.95	1548.0	310.8	212.0	104.7	911.4	601.6	1635.2	3815.4
11	16.08	6750.2	1492.9	195.0	378.3	4684.0	1.95	1548.0	310.5	219.0	95.2	914.3	549.6	1514.5	3534.0
12	16.40	5987.1	1324.1	181.0	370.3	4111.7	1.95	1548.0	310.0	193.0	93.1	942.8	495.3	1367.7	3191.3
13	16.73	4641.2	1030.1	157.0	362.3	3091.7	1.95	1548.0	310.6	192.0	91.1	946.2	398.4	1091.8	2547.7
14	17.06	3612.8	806.3	139.0	354.2	2313.2	1.95	1548.0	310.1	192.0	87.6	950.2	324.7	881.6	2057.1
15	17.40	2668.5	601.5	123.0	346.7	1597.6	1.95	1548.0	309.7	192.0	84.2	954.0	256.9	688.4	1606.3
16	17.75	2502.2	576.4	121.0	338.2	1566.5	1.95	1548.0	309.2	192.0	82.3	956.4	253.2	677.9	1581.8
17	18.11	2313.6	508.9	116.0	330.2	1358.4	1.95	1548.0	308.8	192.0	80.4	958.7	234.5	624.8	1457.8
18	18.47	2225.0	472.0	115.0	322.2	1315.8	1.95	1548.0	308.3	192.0	78.5	961.1	230.7	613.8	1432.3
19	18.84	2200.7	430.6	114.0	314.1	1332.9	1.95	1548.0	307.9	192.0	76.6	963.5	232.5	619.1	1444.7
20	19.21	1753.7	382.7	107.0	306.1	1017.8	1.95	1548.0	307.4	192.0	74.6	965.8	202.7	534.2	1246.6
21	19.60	1645.7	283.3	105.0	283.6	1023.6	1.95	1548.0	307.0	192.0	72.7	968.2	203.4	536.5	1251.9
22	19.99	1459.6	206.1	102.0	259.7	891.7	1.95	1548.0	306.5	192.0	70.8	970.5	191.1	501.3	1169.8
23	20.39	1265.5	177.9	99.0	236.3	752.2	1.95	1548.0	306.1	192.0	68.9	972.9	178.0	464.1	1083.0
24	20.80	1178.9	158.1	97.0	204.1	679.6	1.95	1548.0	305.6	192.0	67.0	975.3	171.3	445.0	1038.5
25	21.21	1086.8	137.7	95.0	168.2	685.9	1.95	1548.0	305.2	192.0	54.2	980.5	165.5	428.6	1000.2
26	21.64	962.9	126.4	94.0	121.7	605.8	1.95	1548.0	304.8	192.0	37.1	1006.0	167.1	433.4	1011.3
27	22.07	805.7	100.7	92.0	74.7	538.3	1.95	1548.0	304.3	192.0	20.6	1023.0	162.2	419.7	979.3
28	22.51	0.0	0.0	200.0	27.4	-227.4	1.95	1548.0	303.9	192.0	0.0	1044.1	102.8	214.1	499.7
29	22.96	0.0	0.0	100.0	13.5	-113.5	1.95	1548.0	303.4	192.0	0.0	1044.5	104.1	248.0	578.8
30	23.42	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	303.0	192.0	0.0	1045.0	105.5	281.8	657.6
31	23.89	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	302.5	192.0	0.0	1045.4	105.5	281.9	657.9
32	24.37	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	302.1	192.0	0.0	1045.9	105.5	282.1	658.2
33	24.86	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	301.6	192.0	0.0	1046.3	105.6	282.2	658.5
34	25.35	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	301.2	192.0	0.0	1046.8	105.6	282.3	658.8
35	25.86	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	300.7	192.0	0.0	1047.2	105.7	282.4	659.0
36	26.38	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	300.3	192.0	0.0	1047.7	105.7	282.5	659.3
37	26.91	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	299.8	192.0	0.0	1048.1	105.8	282.7	659.6
38	27.44	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	299.4	192.0	0.0	1048.6	105.8	282.8	659.9
39	27.99	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	298.9	192.0	0.0	1049.0	105.8	282.9	660.2
40	28.55	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	298.5	192.0	0.0	1049.5	105.9	283.0	660.5
41	29.12	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	298.0	192.0	0.0	1049.9	105.9	283.2	660.8
42	29.71	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	297.6	192.0	0.0	1050.4	106.0	283.3	661.0
43	30.30	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	297.1	192.0	0.0	1050.8	106.0	283.4	661.3
44	30.91	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	296.7	192.0	0.0	1051.3	106.0	283.5	661.6
45	31.53	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	296.2	192.0	0.0	1051.7	106.1	283.6	661.9
46	32.16	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	295.8	192.0	0.0	1052.2	106.1	283.8	662.2
47	32.80	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	295.3	192.0	0.0	1052.6	106.2	283.9	662.5
48	33.46	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	294.9	192.0	0.0	1053.1	106.2	284.0	662.7
49	34.12	0.0	0.0	0.0	0.0	0.0	1.95	774.0	151.2	96.0	0.0	526.7	48.4	143.4	334.8
50	34.81	0.0	0.0	0.0	0.0	0.0	1.95	0.0	0.0	100.0	0.0	-100.0	0.0	0.0	-100.0
		108,567	24,772	4,050	8,654	72,130		62,696	12,640	8,335	2,094	39,706	11,186	30,225	70,425

AGO 53311

ALASKA STATE REVENUES
(MILLIONS OF DOLLARS)

YEAR	OIL PRODUCTION: PROD RATE MBBL/DAY	OIL: ROYALTY PAYMENT	OIL: SEVERANCE TAX	OIL: PROPERTY TAX	OIL: CONSERV. TAX	OIL TOTAL	GAS PRODUCTION: PROD RATE MMMCF/DAY	GAS: ROYALTY PAYMENT	GAS: SEVERANCE TAX	GAS: PROPERTY TAX	GAS TOTAL	STATE INCOME TAX	TOTAL STATE RETURN
1977	1.050	191.6	187.7	36.0	0.4	415.9	0.000	0.0	0.0	0.0	0.0	0.0	415.9
1978	1.425	390.0	382.2	37.9	0.6	810.9	0.000	0.0	0.0	0.0	0.0	197.2	1,008.2
1979	1.500	633.0	603.1	40.0	0.6	1,276.8	0.000	0.0	0.0	0.0	0.0	333.4	1,610.2
1980	1.500	958.1	759.8	41.7	0.6	1,760.4	0.000	0.0	0.0	0.0	0.0	528.6	2,289.1
1981	1.500	977.2	755.2	45.2	0.6	1,778.5	0.000	0.0	0.0	0.0	0.0	535.3	2,313.8
1982	1.500	936.8	750.1	50.1	0.6	1,737.8	0.000	0.0	0.0	3.0	3.0	539.5	2,340.4
1983	1.500	1,016.7	744.4	57.3	0.6	1,819.2	0.000	0.0	0.0	7.5	7.5	543.6	2,370.5
1984	1.500	1,037.1	737.5	64.1	0.6	1,839.5	0.000	0.0	0.0	12.1	12.1	547.3	2,399.0
1985	1.500	1,057.8	734.5	70.4	0.6	1,863.5	2.000	200.6	140.4	17.6	358.8	699.4	2,921.8
1986	1.300	935.1	640.3	68.7	0.5	1,653.8	2.000	200.6	140.4	17.3	358.5	626.4	2,638.8
1987	1.150	843.7	581.7	66.8	0.5	1,492.9	2.000	200.6	140.4	17.0	358.1	573.5	2,424.7
1988	1.600	748.3	512.3	62.9	0.4	1,324.1	2.000	200.6	140.4	16.5	357.7	519.1	2,201.0
1989	0.760	580.1	390.6	59.0	0.3	1,030.1	2.000	200.6	140.4	16.1	357.3	422.0	1,809.5
1990	0.580	451.6	299.3	55.0	0.2	806.3	2.000	200.6	140.4	15.6	356.8	347.9	1,511.0
1991	0.420	333.5	216.6	51.1	0.1	601.5	2.000	200.6	140.4	15.2	356.4	279.8	1,237.8
1992	0.400	324.0	205.0	47.2	0.1	576.4	2.000	200.6	140.4	14.7	355.9	275.9	1,208.3
1993	0.350	289.2	176.3	43.2	0.1	508.9	2.000	200.6	140.4	14.3	355.5	257.0	1,121.5
1994	0.330	278.1	154.3	39.3	0.1	472.0	2.000	200.6	140.4	13.8	355.0	253.1	1,080.1
1995	0.320	275.0	120.0	35.4	0.1	433.6	2.000	200.6	140.4	13.4	354.6	254.7	1,048.9
1996	0.250	219.2	71.9	31.4	0.1	322.7	2.000	200.6	140.4	12.9	354.1	224.7	901.6
1997	0.240	205.7	0.0	27.5	0.1	273.3	2.000	200.6	140.4	12.5	353.7	225.2	852.3
1998	0.200	182.4	0.0	23.6	0.0	206.1	2.000	200.6	140.4	12.0	353.2	212.7	772.1
1999	0.170	158.1	0.0	19.6	0.0	177.9	2.000	200.6	140.4	11.6	352.8	199.5	730.2
2000	0.150	142.3	0.0	15.7	0.0	158.1	2.000	200.6	140.4	11.2	352.3	192.6	703.1
2001	0.130	125.8	0.0	11.8	0.0	137.7	2.000	200.6	140.4	10.7	351.9	185.6	675.2
2002	0.120	118.4	0.0	7.8	0.0	126.4	2.000	200.6	140.4	10.3	351.4	185.5	663.4
2003	0.100	100.7	0.0	0.0	0.0	100.7	2.000	200.6	140.4	9.8	351.0	179.1	630.9
2004	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	9.4	350.5	117.8	468.3
2005	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	8.9	350.1	119.1	469.3
2006	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	8.5	349.6	120.4	470.1
2007	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	8.0	349.2	120.5	469.7
2008	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	7.6	348.7	120.5	469.3
2009	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	7.1	348.3	120.6	468.9
2010	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	6.7	347.8	120.6	468.5
2011	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	6.2	347.4	120.6	468.1
2012	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	5.8	346.9	120.7	467.7
2013	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	5.3	346.5	120.7	467.3
2014	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	4.9	346.0	120.8	466.9
2015	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	4.4	345.6	120.8	466.5
2016	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	4.0	345.2	103.7	448.9
2017	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	3.5	344.7	103.8	448.5
2018	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	3.1	344.3	103.8	448.1
2019	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	2.6	343.8	103.9	447.7
2020	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	2.2	343.4	103.9	447.3
2021	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	1.7	342.9	104.0	446.9
2022	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	1.3	342.5	104.0	446.5
2023	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	0.8	342.0	104.0	446.1
2024	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	0.4	341.6	104.1	445.7
2025	0.000	0.0	0.0	0.0	0.0	0.0	1.000	100.3	70.2	0.0	170.5	47.3	217.9
2026	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0
	7,641T	13,570	9,042	1,109	9	23,732	29,565T	8,127	5,689	389	14,207	11,766	49,705

CUMULATIVE TOTALS

AGO 533112

INDUSTRY CASH FLOWS
(MILLIONS OF DOLLARS)

YEAR 1-50	* * * * * * OIL PRODUCTION * * * * * * WELLHEAD PRICE/BBL	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET OIL CASH FLOW	* * * * * * GAS PRODUCTION * * * * * * WELLHEAD PRICE/MCF	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET GAS CASH FLOW	ST. INC. TAX	FED. INC. TAX	TOTAL NET CASH FLOW
1	4.00	1533.0	415.9	103.0	122.6	891.4	1.95	0.0	0.0	26.0	0.0	-26.0	0.0	259.6	605.7
2	6.00	3120.7	810.9	140.0	161.9	2007.8	1.95	0.0	0.0	33.0	0.0	-33.0	137.2	533.2	1244.3
3	9.25	5054.3	1276.8	156.0	187.4	3444.0	1.95	0.0	0.0	32.0	0.0	-32.0	333.4	923.6	2155.0
4	14.00	7665.0	1760.4	163.0	290.6	5450.9	1.95	0.0	0.0	36.0	0.0	-36.0	528.6	1465.8	3420.3
5	14.28	7818.3	1778.5	171.0	369.0	5499.7	1.95	0.0	0.0	41.0	92.6	-133.6	535.3	1449.2	3381.5
6	14.56	7974.6	1797.8	173.0	511.9	5491.8	1.95	0.0	3.0	48.0	148.5	-199.6	539.5	1425.8	3326.8
7	14.85	8134.1	1819.2	174.0	590.3	5550.4	1.95	0.0	7.5	54.0	172.8	-234.3	543.6	1431.7	3340.7
8	15.15	8296.8	1839.5	178.0	668.8	5610.5	1.95	0.0	12.1	60.0	235.1	-307.2	547.3	1426.7	3329.1
9	15.45	8462.7	1863.5	230.0	462.7	5906.4	1.95	1850.8	358.8	192.0	104.9	1195.0	699.4	1920.6	4481.4
10	15.76	7481.0	1653.8	210.0	476.3	5140.8	1.95	1850.6	358.5	212.0	104.7	1175.4	626.4	1706.9	3982.8
11	16.08	6750.2	1492.9	195.0	378.3	4683.9	1.95	1841.1	358.1	219.0	95.2	1168.7	573.5	1583.7	3695.4
12	16.40	5987.1	1324.1	181.0	370.3	4111.7	1.95	1839.0	357.7	193.0	93.1	1195.1	519.1	1436.3	3351.4
13	16.73	4641.2	1030.1	157.0	362.3	3091.7	1.95	1837.0	357.3	192.0	91.1	1196.6	422.0	1159.9	2706.4
14	17.06	3612.8	806.3	139.0	354.2	2313.2	1.95	1833.5	356.8	192.0	87.6	1197.0	347.9	948.7	2213.6
15	17.40	2688.5	601.5	123.0	346.2	1597.6	1.95	1830.1	356.4	192.0	84.2	1197.5	279.8	754.6	1760.7
16	17.75	2592.2	576.4	121.0	338.2	1556.5	1.95	1828.2	355.9	192.0	82.3	1197.9	275.9	743.5	1735.0
17	18.11	2313.6	508.9	116.0	330.2	1358.4	1.95	1826.3	355.5	192.0	80.4	1198.4	257.0	689.9	1609.8
18	18.47	2225.0	472.0	115.0	322.2	1315.8	1.95	1824.4	355.0	192.0	78.5	1198.9	253.1	678.4	1583.1
19	18.84	2200.7	439.6	114.0	314.1	1332.9	1.95	1822.5	354.6	192.0	76.6	1199.3	254.7	683.2	1594.3
20	19.21	1753.7	322.7	107.0	306.1	1017.8	1.95	1820.5	354.1	192.0	74.6	1199.7	224.7	597.8	1394.9
21	19.60	1645.7	283.3	105.0	283.6	1023.6	1.95	1818.6	353.7	192.0	72.7	1200.1	225.2	599.5	1399.0
22	19.99	1459.6	206.1	102.0	259.7	891.7	1.95	1816.7	353.2	192.0	70.8	1200.6	212.7	563.9	1315.7
23	20.39	1266.5	177.9	99.0	236.3	752.2	1.95	1814.8	352.8	192.0	68.9	1201.1	199.5	526.1	1227.7
24	20.80	1138.9	158.1	97.0	204.1	679.6	1.95	1812.9	352.3	192.0	67.0	1201.5	192.6	506.5	1182.0
25	21.21	1006.8	137.7	95.0	168.2	605.9	1.95	1800.1	351.9	192.0	54.2	1202.0	185.6	486.7	1135.6
26	21.64	947.9	126.4	94.0	121.7	605.8	1.95	1783.0	351.4	192.0	37.1	1202.4	185.5	486.8	1135.8
27	22.07	885.7	100.7	92.0	74.7	538.3	1.95	1766.5	351.0	192.0	20.6	1202.9	179.1	468.6	1093.4
28	22.51	0.0	0.0	200.0	27.4	-227.4	1.95	1745.9	350.5	192.0	0.0	1203.4	117.8	257.4	600.7
29	22.96	0.0	0.0	100.0	13.5	-113.5	1.95	1745.9	350.1	192.0	0.0	1203.8	119.1	291.3	679.8
30	23.42	0.0	0.0	0.0	0.0	0.0	1.95	1745.9	349.6	192.0	0.0	1204.2	120.4	325.1	758.6
31	23.89	0.0	0.0	0.0	0.0	0.0	1.95	1745.9	349.2	192.0	0.0	1204.7	120.5	325.2	758.9
32	24.37	0.0	0.0	0.0	0.0	0.0	1.95	1745.9	348.7	192.0	0.0	1205.1	120.5	325.3	759.2
33	24.86	0.0	0.0	0.0	0.0	0.0	1.95	1745.9	348.3	192.0	0.0	1205.6	120.6	325.5	759.5
34	25.35	0.0	0.0	0.0	0.0	0.0	1.95	1745.9	347.8	192.0	0.0	1206.0	120.6	325.6	759.8
35	25.86	0.0	0.0	0.0	0.0	0.0	1.95	1745.9	347.4	192.0	0.0	1206.5	120.6	325.7	760.0
36	26.38	0.0	0.0	0.0	0.0	0.0	1.95	1745.9	346.9	192.0	0.0	1206.9	120.7	325.8	760.3
37	26.91	0.0	0.0	0.0	0.0	0.0	1.95	1745.9	346.5	192.0	0.0	1207.4	120.7	325.9	760.6
38	27.44	0.0	0.0	0.0	0.0	0.0	1.95	1745.9	346.0	192.0	0.0	1207.8	120.8	326.1	760.9
39	27.99	0.0	0.0	0.0	0.0	0.0	1.95	1745.9	345.6	192.0	0.0	1208.3	120.8	326.2	761.2
40	28.55	0.0	0.0	0.0	0.0	0.0	1.95	1563.9	345.2	192.0	0.0	1026.7	103.7	276.8	646.0
41	29.12	0.0	0.0	0.0	0.0	0.0	1.95	1563.9	344.7	192.0	0.0	1027.2	103.8	277.0	646.3
42	29.71	0.0	0.0	0.0	0.0	0.0	1.95	1563.9	344.3	192.0	0.0	1027.6	103.8	277.1	646.6
43	30.30	0.0	0.0	0.0	0.0	0.0	1.95	1563.9	343.8	192.0	0.0	1028.1	103.9	277.2	646.9
44	30.91	0.0	0.0	0.0	0.0	0.0	1.95	1563.9	343.4	192.0	0.0	1028.5	103.9	277.3	647.2
45	31.53	0.0	0.0	0.0	0.0	0.0	1.95	1563.9	342.9	192.0	0.0	1029.0	104.0	277.5	647.5
46	32.16	0.0	0.0	0.0	0.0	0.0	1.95	1563.9	342.5	192.0	0.0	1029.4	104.0	277.6	647.7
47	32.80	0.0	0.0	0.0	0.0	0.0	1.95	1563.9	342.0	192.0	0.0	1029.9	104.0	277.7	648.0
48	33.46	0.0	0.0	0.0	0.0	0.0	1.95	1563.9	341.6	192.0	0.0	1030.3	104.1	277.8	648.3
49	34.12	0.0	0.0	0.0	0.0	0.0	1.95	781.9	170.5	96.0	0.0	515.4	47.3	140.4	327.6
50	34.81	0.0	0.0	0.0	0.0	0.0	1.95	0.0	0.0	100.0	0.0	-100.0	0.0	0.0	-100.0
		108,567	23,747	4,050	8,654	72,130		70,427	14,207	8,335	2,094	45,871	11,766	31,900	74,335

AGO 533113

ALASKA STATE REVENUES
(BILLIONS OF DOLLARS)

YEAR	PROD RATE MBBL/DAY	OIL ROYALTY PAYMENT	OIL SEVERANCE TAX	OIL PROPERTY TAX	OIL CONSERV. TAX	OIL TOTAL	GAS PROD RATE MMMCF/DAY	GAS ROYALTY PAYMENT	GAS SEVERANCE TAX	GAS PROPERTY TAX	GAS TOTAL	STATE INCOME TAX	TOTAL STATE RETURN
1977	1.050	191.6	187.7	36.0	0.4	415.9	0.000	0.0	0.0	0.0	0.0	0.0	415.9
1978	1.425	390.0	382.2	37.9	0.6	810.9	0.000	0.0	0.0	0.0	0.0	197.2	1,008.2
1979	1.500	633.0	603.1	40.0	0.6	1,276.8	0.000	0.0	0.0	0.0	0.0	333.4	1,610.2
1980	1.500	958.1	759.8	41.7	0.6	1,760.4	0.000	0.0	0.0	0.0	0.0	528.6	2,289.1
1981	1.500	977.2	755.2	45.2	0.6	1,778.5	0.000	0.0	0.0	0.0	0.0	535.3	2,313.8
1982	1.500	996.8	750.1	50.1	0.6	1,797.8	0.000	0.0	0.0	3.0	3.0	539.5	2,340.4
1983	1.500	1,016.7	744.4	57.3	0.6	1,819.2	0.000	0.0	0.0	7.5	7.5	543.6	2,370.5
1984	1.500	1,037.1	737.5	64.1	0.6	1,839.5	0.000	0.0	0.0	12.1	12.1	547.3	2,399.0
1985	1.500	1,057.8	734.5	70.4	0.6	1,863.5	2.000	177.9	124.5	17.6	320.1	691.7	2,875.4
1986	1.300	935.1	649.3	68.7	0.5	1,653.8	2.000	177.9	124.5	17.3	319.8	618.7	2,592.4
1987	1.150	843.7	581.7	66.8	0.5	1,492.9	2.000	177.9	124.5	17.0	319.5	566.7	2,379.2
1988	1.000	748.3	512.3	62.9	0.4	1,324.1	2.000	177.9	124.5	16.5	319.0	512.4	2,155.7
1989	0.760	580.1	380.6	59.0	0.3	1,030.1	2.000	177.9	124.5	16.1	318.6	415.5	1,764.4
1990	0.580	451.6	299.3	55.0	0.2	806.3	2.000	177.9	124.5	15.6	318.1	341.8	1,466.3
1991	0.420	333.5	216.6	51.1	0.1	601.5	2.000	177.9	124.5	15.2	317.7	274.0	1,193.3
1992	0.400	324.9	205.9	47.3	0.1	576.4	2.000	177.9	124.5	14.7	317.2	270.3	1,164.0
1993	0.350	283.2	176.3	43.2	0.1	508.9	2.000	177.9	124.5	14.3	316.8	251.6	1,077.4
1994	0.330	278.1	154.3	39.3	0.1	472.0	2.000	177.9	124.5	13.8	316.3	247.8	1,036.2
1995	0.320	275.0	129.0	35.4	0.1	439.6	2.000	177.9	124.5	13.4	315.9	249.6	1,005.2
1996	0.250	219.2	71.9	31.4	0.1	322.7	2.000	177.9	124.5	12.9	315.4	219.8	858.1
1997	0.230	205.7	0.0	27.5	0.1	233.3	2.000	177.9	124.5	12.5	315.0	220.5	768.9
1998	0.200	182.4	0.0	23.6	0.0	206.1	2.000	177.9	124.5	12.0	314.5	208.2	728.9
1999	0.170	158.1	0.0	19.6	0.0	177.9	2.000	177.9	124.5	11.6	314.1	195.1	687.2
2000	0.150	142.3	0.0	15.7	0.0	158.1	2.000	177.9	124.5	11.2	313.6	188.4	660.3
2001	0.130	125.8	0.0	11.8	0.0	137.7	2.000	177.9	124.5	10.7	313.2	182.6	633.6
2002	0.120	118.4	0.0	7.8	0.0	126.4	2.000	177.9	124.5	10.3	312.8	184.2	623.4
2003	0.100	100.7	0.0	0.0	0.0	100.7	2.000	177.9	124.5	9.8	312.3	179.3	592.5
2004	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	9.4	311.9	119.9	431.8
2005	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.9	311.4	121.3	432.7
2006	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.5	311.0	122.6	433.6
2007	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.0	310.5	122.6	433.2
2008	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	7.6	310.1	122.7	432.8
2009	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	7.1	309.6	122.7	432.4
2010	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	6.7	309.2	122.7	432.0
2011	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	6.2	308.7	122.8	431.5
2012	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	5.8	308.3	122.8	431.1
2013	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	5.3	307.8	122.9	430.7
2014	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.9	307.4	122.9	430.3
2015	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.4	306.9	122.9	429.9
2016	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.0	306.5	105.9	412.4
2017	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	3.5	306.0	105.9	412.0
2018	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	3.1	305.6	106.0	411.6
2019	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	2.6	305.1	106.0	411.2
2020	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	2.2	304.7	106.0	410.8
2021	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	1.7	304.2	106.1	410.4
2022	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	1.3	303.8	106.1	410.0
2023	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.8	303.3	106.2	409.6
2024	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.4	302.9	106.2	409.2
2025	0.000	0.0	0.0	0.0	0.0	0.0	1.000	88.9	62.2	0.0	151.2	48.4	199.7
2026	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0
	7,641T	13,570	9,042	1,109	9	23,732	29,565T	7,206	5,044	389	12,640	11,717	48,090

CUMULATIVE TOTALS

AGO 533114

INDUSTRY CASH FLOWS
(MILLIONS OF DOLLARS)

YEAR 1-50	OIL PRODUCTION * * * * * * WELLHEAD PRICE/BL	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET OIL CASH FLOW	GAS PRODUCTION * * * * * * WELLHEAD PRICE/MCF	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET GAS CASH FLOW	ST. INC. TAX	FED. INC. TAX	TOTAL NET CASH FLOW
1	4.00	1503.0	415.9	103.0	122.6	891.4	1.95	0.0	0.0	26.0	0.0	-26.0	0.0	259.6	605.7
2	6.00	3120.7	810.9	140.0	161.9	2007.8	1.95	0.0	0.0	33.0	0.0	-33.0	197.2	533.2	1244.3
3	9.25	5004.3	1276.8	156.0	187.4	3444.0	1.95	0.0	0.0	32.0	0.0	-32.0	333.4	923.6	2155.0
4	14.00	7665.0	1760.4	163.0	290.6	5450.9	1.95	0.0	0.0	36.0	0.0	-36.0	528.6	1465.8	3420.3
5	14.28	7818.3	1778.5	171.0	369.0	5499.7	1.95	0.0	0.0	41.0	92.6	-133.6	535.3	1449.2	3381.5
6	14.56	7974.6	1797.8	173.0	511.9	5491.8	1.95	0.0	3.0	48.0	148.5	-199.6	533.5	1425.8	3326.8
7	14.85	8134.1	1819.2	174.0	590.3	5550.4	1.95	0.0	7.5	54.0	172.8	-234.3	543.6	1431.7	3340.7
8	15.15	8296.8	1839.5	178.0	668.8	5610.5	1.95	0.0	12.1	60.0	235.1	-307.2	547.3	1426.7	3329.1
9	15.45	8462.7	1863.5	230.0	462.7	5906.4	1.95	1730.0	320.1	192.0	104.9	1112.9	691.7	1838.2	4429.3
10	15.76	7481.0	1653.8	210.0	476.3	5140.8	1.95	1730.0	319.8	212.0	104.7	1093.4	618.7	1684.6	3930.9
11	16.08	6750.2	1492.9	195.0	378.3	4683.9	1.95	1730.0	319.5	219.0	95.2	1096.3	566.7	1564.0	3649.4
12	16.40	5987.1	1324.1	181.0	370.3	4111.7	1.95	1730.0	319.0	193.0	93.1	1124.8	512.4	1417.2	3306.8
13	16.73	4641.2	1030.1	157.0	362.3	3091.7	1.95	1730.0	318.6	192.0	91.1	1128.2	415.5	1141.3	2663.1
14	17.06	3612.8	806.3	133.0	354.2	2313.2	1.95	1730.0	318.1	192.0	87.6	1132.2	341.8	931.0	2172.5
15	17.40	2668.5	601.5	123.0	346.2	1597.6	1.95	1730.0	317.7	192.0	84.2	1136.0	274.0	737.9	1721.7
16	17.75	2502.2	576.4	121.0	338.2	1556.5	1.95	1730.0	317.2	192.0	82.3	1138.4	270.3	727.4	1697.2
17	18.11	2313.6	508.3	116.0	330.2	1358.4	1.95	1730.0	316.8	192.0	80.4	1140.7	251.6	674.2	1573.2
18	18.47	2225.0	472.0	115.0	322.2	1315.8	1.95	1730.0	316.3	192.0	78.5	1143.1	247.8	663.3	1547.7
19	18.84	2200.7	439.6	114.0	314.1	1332.9	1.95	1730.0	315.9	192.0	76.6	1145.5	249.6	668.6	1560.1
20	19.21	1753.7	322.7	107.0	306.1	1017.8	1.95	1730.0	315.4	192.0	74.6	1147.8	219.8	583.7	1362.0
21	19.60	1645.7	233.3	105.0	283.6	1023.6	1.95	1730.0	315.0	192.0	72.7	1150.2	220.5	586.0	1367.3
22	19.99	1459.6	206.1	102.0	259.7	891.7	1.95	1730.0	314.5	192.0	70.8	1152.5	208.2	550.8	1285.3
23	20.39	1265.5	177.9	99.0	236.3	752.2	1.95	1730.0	314.1	192.0	68.9	1154.9	195.1	513.6	1198.4
24	20.80	1138.9	158.1	97.0	204.1	679.6	1.95	1730.0	313.6	192.0	67.0	1157.3	188.4	494.5	1153.9
25	21.21	1006.8	137.7	95.0	168.2	605.9	1.95	1730.0	313.2	192.0	54.2	1170.5	182.6	478.1	1115.6
26	21.64	947.9	126.4	94.0	121.7	605.8	1.95	1730.0	312.8	192.0	37.1	1188.0	184.2	482.9	1126.7
27	22.07	805.7	100.7	92.0	74.7	538.3	1.95	1730.0	312.3	192.0	20.6	1205.0	179.3	469.1	1094.7
28	22.51	0.0	0.0	200.0	27.4	-227.4	1.95	1730.0	311.9	192.0	0.0	1226.1	119.9	263.6	615.1
29	22.96	0.0	0.0	100.0	13.5	-113.5	1.95	1730.0	311.4	192.0	0.0	1226.5	121.3	297.5	694.2
30	23.42	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	311.0	192.0	0.0	1227.0	122.6	331.3	773.1
31	23.89	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	310.5	192.0	0.0	1227.4	122.6	331.4	773.3
32	24.37	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	310.1	192.0	0.0	1227.9	122.7	331.5	773.6
33	24.86	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	309.6	192.0	0.0	1228.3	122.7	331.6	773.9
34	25.35	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	309.2	192.0	0.0	1228.8	122.7	331.8	774.2
35	25.86	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	308.7	192.0	0.0	1229.2	122.8	331.9	774.5
36	26.38	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	308.3	192.0	0.0	1229.7	122.8	332.0	774.8
37	26.91	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	307.8	192.0	0.0	1230.1	122.9	332.1	775.0
38	27.44	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	307.4	192.0	0.0	1230.6	122.9	332.3	775.3
39	27.99	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	306.9	192.0	0.0	1231.0	122.9	332.4	775.6
40	28.55	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	306.5	192.0	0.0	1049.5	105.9	283.0	660.5
41	29.12	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	306.0	192.0	0.0	1049.9	105.9	283.2	660.8
42	29.71	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	305.6	192.0	0.0	1050.4	106.0	283.3	661.0
43	30.30	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	305.1	192.0	0.0	1050.8	106.0	283.4	661.3
44	30.91	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	304.7	192.0	0.0	1051.3	106.0	283.5	661.6
45	31.53	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	304.2	192.0	0.0	1051.7	106.1	283.6	661.9
46	32.16	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	303.8	192.0	0.0	1052.2	106.1	283.8	662.2
47	32.80	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	303.3	192.0	0.0	1052.6	106.2	283.9	662.5
48	33.46	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	302.9	192.0	0.0	1053.1	106.2	284.0	662.7
49	34.12	0.0	0.0	0.0	0.0	0.0	1.95	774.0	151.2	96.0	0.0	526.7	48.4	143.4	334.8
50	34.81	0.0	0.0	0.0	0.0	0.0	1.95	0.0	0.0	100.0	0.0	-100.0	0.0	0.0	-100.0
		100,567	27,732	4,050	8,654	72,130		68,338	12,640	8,335	2,094	45,348	11,717	31,758	74,003

CUMULATIVE TOTALS

AGO 533115

ALASKA STATE REVENUES
(MILLIONS OF DOLLARS)

YEAR	OIL PRODUCTION PROD RATE MBBL/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	CONSERV. TAX	OIL TOTAL	GAS PRODUCTION PROD RATE MMMCF/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	GAS TOTAL	STATE INCOME TAX	TOTAL STATE RETURN
1977	1.050	191.6	187.7	36.0	0.4	415.9	0.000	0.0	0.0	0.0	0.0	0.0	415.9
1978	1.425	390.0	382.2	37.9	0.6	810.9	0.000	0.0	0.0	0.0	0.0	197.2	1,008.2
1979	1.500	633.0	603.1	40.0	0.6	1,276.8	0.000	0.0	0.0	0.0	0.0	333.4	1,610.2
1980	1.560	958.1	759.8	41.7	0.6	1,760.4	0.000	0.0	0.0	0.0	0.0	528.6	2,289.1
1981	1.500	977.2	755.2	45.2	0.6	1,778.5	0.000	0.0	0.0	0.0	0.0	535.3	2,313.8
1982	1.500	906.8	750.1	50.1	0.6	1,797.8	0.000	0.0	0.0	3.0	3.0	539.5	2,340.4
1983	1.500	1,016.7	744.4	57.3	0.6	1,819.2	0.000	0.0	0.0	7.5	7.5	543.6	2,370.5
1984	1.500	1,037.1	737.5	64.1	0.6	1,839.5	0.000	0.0	0.0	12.1	12.1	547.3	2,399.0
1985	1.500	1,057.8	734.5	70.4	0.6	1,863.5	2.000	177.9	124.5	17.6	320.1	701.5	2,885.2
1986	1.300	935.1	649.3	68.7	0.5	1,653.8	2.000	177.9	124.5	17.3	319.8	628.5	2,602.2
1987	1.150	843.7	581.7	66.8	0.5	1,492.9	2.000	177.9	124.5	17.0	319.5	575.7	2,388.1
1988	1.000	748.3	512.3	62.9	0.4	1,324.1	2.000	177.9	124.5	16.5	319.0	521.2	2,164.4
1989	0.760	580.1	390.6	59.0	0.3	1,030.1	2.000	177.9	124.5	16.1	318.6	424.1	1,772.9
1990	0.580	451.6	299.3	55.0	0.2	806.3	2.000	177.9	124.5	15.6	318.1	350.0	1,474.5
1991	0.420	333.5	216.6	51.1	0.1	601.5	2.000	177.9	124.5	15.2	317.7	281.9	1,201.3
1992	0.400	324.0	205.0	47.2	0.1	576.4	2.000	177.9	124.5	14.7	317.2	278.0	1,171.8
1993	0.350	280.2	176.3	43.2	0.1	508.9	2.000	177.9	124.5	14.3	316.8	259.2	1,085.0
1994	0.330	278.1	154.3	39.3	0.1	472.0	2.000	177.9	124.5	13.8	316.3	255.2	1,043.6
1995	0.320	275.0	129.0	35.4	0.1	439.6	2.000	177.9	124.5	13.4	315.9	256.8	1,012.4
1996	0.250	219.2	71.9	31.4	0.1	322.7	2.000	177.9	124.5	12.9	315.4	226.8	865.1
1997	0.230	205.7	0.0	27.5	0.1	233.3	2.000	177.9	124.5	12.5	315.0	227.3	775.7
1998	0.200	182.4	0.0	23.6	0.0	206.1	2.000	177.9	124.5	12.0	314.5	214.8	735.6
1999	0.170	158.1	0.0	19.6	0.0	177.9	2.000	177.9	124.5	11.6	314.1	201.6	693.7
2000	0.150	142.3	0.0	15.7	0.0	158.1	2.000	177.9	124.5	11.2	313.6	194.7	666.6
2001	0.130	125.8	0.0	11.8	0.0	137.7	2.000	177.9	124.5	10.7	313.2	187.7	638.7
2002	0.120	118.4	0.0	7.8	0.0	126.4	2.000	177.9	124.5	10.3	312.8	187.7	626.9
2003	0.100	100.7	0.0	0.0	0.0	100.7	2.000	177.9	124.5	9.8	312.3	181.3	594.4
2004	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	9.4	311.9	119.9	431.8
2005	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.9	311.4	121.3	432.7
2006	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.5	311.0	122.6	433.6
2007	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.0	310.5	122.6	433.2
2008	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	7.6	310.1	122.7	432.8
2009	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	7.1	309.6	122.7	432.4
2010	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	6.7	309.2	122.7	432.0
2011	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	6.2	308.7	122.8	431.5
2012	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	5.8	308.3	122.8	431.1
2013	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	5.3	307.8	122.9	430.7
2014	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.9	307.4	122.9	430.3
2015	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.4	306.9	122.9	429.9
2016	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.0	306.5	105.9	412.4
2017	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	3.5	306.0	105.9	412.0
2018	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	3.1	305.6	106.0	411.6
2019	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	2.6	305.1	106.0	411.2
2020	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	2.2	304.7	106.0	410.8
2021	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	1.7	304.2	106.1	410.4
2022	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	1.3	303.8	106.1	410.0
2023	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.8	303.3	106.2	409.6
2024	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.4	302.9	106.2	409.2
2025	0.000	0.0	0.0	0.0	0.0	0.0	1.000	88.9	62.2	0.0	151.2	48.4	199.7
2026	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0
	7,641T	13,570	9,042	1,100	9	23,732	29,565T	7,206	5,044	389	12,640	11,852	48,226

CUMULATIVE TOTALS

AGO 533116

INDUSTRY CASH FLOWS
(MILLIONS OF DOLLARS)

YEAR 1-50	WELLHEAD PRICE/BBL	GROSS INCOME	STATE TAXE	OPERAT COSTS	CAPITAL COSTS	NET OIL CASH FLOW	WELLHEAD PRICE/MCF	GROSS INCOME	STATE TAXE	OPERAT COSTS	CAPITAL COSTS	NET GAS CASH FLOW	ST. INC. TAX	FED. INC. TAX	TOTAL NET CASH FLOW
	* * * * * * OIL PRODUCTION * * * * * *						* * * * * * GAS PRODUCTION * * * * * *								
1	4.00	1533.0	415.9	103.0	122.6	891.4	1.95	0.0	0.0	26.0	0.0	-26.0	0.0	259.6	605.7
2	6.00	3120.7	810.9	140.0	161.9	2007.8	1.95	0.0	0.0	33.0	0.0	-33.0	197.2	533.2	1244.3
3	9.25	5064.3	1276.8	156.0	187.4	3444.0	1.95	0.0	0.0	32.0	0.0	-32.0	333.4	923.6	2155.0
4	14.00	7665.0	1760.4	163.0	290.6	5450.9	1.95	0.0	0.0	36.0	0.0	-36.0	528.6	1465.8	3420.3
5	14.28	7818.3	1778.5	171.0	369.0	5499.7	1.95	0.0	0.0	41.0	92.6	-133.6	535.3	1449.2	3381.5
6	14.56	7974.6	1797.8	173.0	511.9	5491.8	1.95	0.0	3.0	48.0	148.5	-199.6	539.5	1425.8	3326.8
7	14.85	8134.1	1819.2	174.0	590.3	5550.4	1.95	0.0	7.5	54.0	172.8	-234.3	543.6	1431.7	3340.7
8	15.15	8296.8	1830.5	178.0	668.8	5610.5	1.95	0.0	12.1	60.0	235.1	-307.2	547.3	1426.7	3329.1
9	15.45	8462.7	1863.5	230.0	462.7	5906.4	1.95	1834.9	320.1	192.0	104.9	1217.8	701.5	1926.8	4495.8
10	15.76	7481.0	1653.8	210.0	476.3	5140.8	1.95	1834.7	319.8	212.0	104.7	1198.1	620.5	1713.1	3997.3
11	16.08	6750.2	1492.9	195.0	378.3	4683.9	1.95	1825.2	319.5	219.0	95.2	1191.5	575.7	1589.9	3709.8
12	16.40	5987.1	1324.1	181.0	370.3	4111.7	1.95	1823.1	319.0	193.0	93.1	1217.9	521.2	1442.5	3365.8
13	16.73	4641.2	1030.1	157.0	362.3	3091.7	1.95	1821.1	318.6	192.0	91.1	1219.3	424.1	1166.1	2720.9
14	17.06	3612.8	806.3	139.0	354.2	2313.2	1.95	1817.6	318.1	192.0	87.6	1219.8	350.0	954.9	2228.1
15	17.40	2668.5	601.5	123.0	346.2	1597.6	1.95	1814.2	317.7	192.0	84.2	1220.2	281.9	760.7	1775.1
16	17.75	2592.2	576.4	121.0	338.2	1556.5	1.95	1812.3	317.2	192.0	82.3	1220.7	278.0	749.7	1749.4
17	18.11	2313.6	508.9	116.0	330.2	1358.4	1.95	1810.4	316.8	192.0	80.4	1221.1	259.2	696.1	1624.2
18	18.47	2225.0	472.0	115.0	322.2	1315.8	1.95	1808.5	316.3	192.0	78.5	1221.6	255.2	684.6	1597.5
19	18.84	2200.7	439.6	114.0	314.1	1332.9	1.95	1806.6	315.9	192.0	76.6	1222.1	256.8	689.4	1608.7
20	19.21	1753.7	322.7	107.0	306.1	1017.8	1.95	1804.6	315.4	192.0	74.6	1222.4	226.8	604.0	1409.3
21	19.60	1645.7	233.3	105.0	283.6	1023.6	1.95	1802.7	315.0	192.0	72.7	1222.9	227.3	605.7	1413.4
22	19.99	1459.6	206.1	102.0	259.7	891.7	1.95	1800.8	314.5	192.0	70.8	1223.3	214.8	570.0	1330.2
23	20.39	1265.5	177.9	99.0	236.3	752.2	1.95	1798.9	314.1	192.0	68.9	1223.8	201.6	532.3	1242.1
24	20.80	1138.9	158.1	97.0	204.1	679.6	1.95	1797.0	313.6	192.0	67.0	1224.3	194.7	512.7	1196.4
25	21.21	1006.8	137.7	95.0	168.2	605.9	1.95	1794.2	313.2	192.0	54.2	1224.7	187.7	492.8	1150.0
26	21.64	947.9	126.4	94.0	121.7	605.8	1.95	1767.1	312.8	192.0	37.1	1225.1	187.7	492.9	1150.2
27	22.07	805.7	100.7	92.0	74.7	538.3	1.95	1750.6	312.3	192.0	20.6	1225.6	181.3	474.7	1107.8
28	22.51	0.0	0.0	200.0	27.4	-227.4	1.95	1730.0	311.9	192.0	0.0	1226.1	119.9	263.6	615.1
29	22.96	0.0	0.0	100.0	13.5	-113.5	1.95	1730.0	311.4	192.0	0.0	1226.5	121.3	297.5	694.2
30	23.42	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	311.0	192.0	0.0	1227.0	122.6	331.3	773.1
31	23.89	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	310.5	192.0	0.0	1227.4	122.6	331.4	773.3
32	24.37	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	310.1	192.0	0.0	1227.9	122.7	331.5	773.6
33	24.86	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	309.6	192.0	0.0	1228.3	122.7	331.6	773.9
34	25.35	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	309.2	192.0	0.0	1228.8	122.7	331.8	774.2
35	25.86	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	308.7	192.0	0.0	1229.2	122.8	331.9	774.5
36	26.38	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	308.3	192.0	0.0	1229.7	122.8	332.0	774.8
37	26.91	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	307.8	192.0	0.0	1230.1	122.9	332.1	775.0
38	27.44	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	307.4	192.0	0.0	1230.6	122.9	332.3	775.3
39	27.99	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	306.9	192.0	0.0	1231.0	122.9	332.4	775.6
40	28.55	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	306.5	192.0	0.0	1049.5	105.9	283.0	660.5
41	29.12	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	306.0	192.0	0.0	1049.9	105.9	283.2	660.8
42	29.71	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	305.6	192.0	0.0	1050.4	106.0	283.3	661.0
43	30.30	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	305.1	192.0	0.0	1050.8	106.0	283.4	661.3
44	30.91	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	304.7	192.0	0.0	1051.3	106.0	283.5	661.6
45	31.53	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	304.2	192.0	0.0	1051.7	106.1	283.6	661.9
46	32.16	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	303.8	192.0	0.0	1052.2	106.1	283.8	662.2
47	32.80	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	303.3	192.0	0.0	1052.6	106.2	283.9	662.5
48	33.46	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	302.9	192.0	0.0	1053.1	106.2	284.0	662.7
49	34.12	0.0	0.0	0.0	0.0	0.0	1.95	774.0	151.2	96.0	0.0	526.7	48.4	143.4	334.8
50	34.81	0.0	0.0	0.0	0.0	0.0	1.95	0.0	0.0	100.0	0.0	-100.0	0.0	0.0	-100.0
		108,567	23,757	4,050	8,654	72,130		69,782	12,640	8,335	2,094	46,793	11,852	32,151	74,919

CUMULATIVE TOTALS

AGO 533117

ALASKA STATE REVENUES
(MILLIONS OF DOLLARS)

YEAR	OIL PRODUCTION: PROD RATE MBBL/DAY	OIL: ROYALTY PAYMENT	OIL: SEVERANCE TAX	OIL: PROPERTY TAX	OIL: CONSERV. TAX	OIL TOTAL	GAS PRODUCTION: PROD RATE MMCF/DAY	GAS: ROYALTY PAYMENT	GAS: SEVERANCE TAX	GAS: PROPERTY TAX	GAS TOTAL	STATE INCOME TAX	TOTAL STATE RETURN
1977	1.050	191.6	187.7	36.0	0.4	415.9	0.000	0.0	0.0	0.0	0.0	0.0	415.9
1978	1.425	390.0	382.2	37.9	0.6	810.9	0.000	0.0	0.0	0.0	0.0	197.2	1,008.2
1979	1.500	633.0	603.1	40.0	0.6	1,276.8	0.000	0.0	0.0	0.0	0.0	333.4	1,610.2
1980	1.500	958.1	759.8	41.7	0.6	1,760.4	0.000	0.0	0.0	0.0	0.0	528.6	2,289.1
1981	1.500	977.2	755.2	45.2	0.6	1,778.5	0.000	0.0	0.0	0.0	0.0	535.3	2,313.8
1982	1.500	996.8	750.1	50.1	0.6	1,797.8	0.000	0.0	0.0	0.9	0.9	539.7	2,338.5
1983	1.500	1,016.7	744.4	57.3	0.6	1,819.2	0.000	0.0	0.0	2.5	2.5	544.1	2,365.9
1984	1.500	1,037.1	737.5	64.1	0.6	1,839.5	0.000	0.0	0.0	4.3	4.3	548.0	2,391.9
1985	1.500	1,057.8	734.5	70.4	0.6	1,863.5	2.000	142.0	128.1	6.7	276.9	678.9	2,819.5
1986	1.300	905.1	649.3	68.7	0.5	1,653.2	2.000	142.1	128.1	7.5	277.8	605.9	2,537.5
1987	1.150	843.7	581.7	66.8	0.5	1,492.9	2.000	143.2	128.0	8.3	279.6	553.7	2,326.3
1988	1.000	748.3	512.3	62.9	0.4	1,324.1	2.000	143.5	127.9	8.0	279.6	499.4	2,103.2
1989	0.700	580.1	390.6	59.0	0.3	1,030.1	2.000	143.8	127.9	7.8	279.6	402.4	1,712.2
1990	0.580	491.6	299.3	55.0	0.2	806.3	2.000	144.2	127.9	7.6	279.8	328.6	1,414.7
1991	0.420	333.5	216.6	51.1	0.1	601.5	2.000	144.6	127.8	7.4	279.9	260.8	1,142.3
1992	0.400	324.0	205.0	47.2	0.1	576.4	2.000	144.9	127.8	7.2	279.9	257.0	1,113.4
1993	0.350	289.2	176.3	43.2	0.1	508.9	2.000	145.1	127.8	6.9	279.9	238.3	1,027.2
1994	0.330	278.1	154.3	39.3	0.1	472.0	2.000	145.3	127.8	6.7	279.9	234.4	986.4
1995	0.320	275.0	120.0	35.4	0.1	430.6	2.000	145.6	127.7	6.5	279.9	236.2	955.8
1996	0.250	219.2	71.9	31.4	0.1	322.7	2.000	145.8	127.7	6.3	279.9	206.4	809.1
1997	0.230	205.7	0.0	27.5	0.1	233.3	2.000	146.1	127.7	6.1	279.9	207.0	720.3
1998	0.200	182.4	0.0	23.6	0.0	206.1	2.000	146.3	127.7	5.9	279.9	194.6	680.7
1999	0.170	156.1	0.0	19.6	0.0	177.9	2.000	146.5	127.6	5.6	279.9	181.5	639.4
2000	0.150	142.3	0.0	15.7	0.0	158.1	2.000	146.8	127.6	5.4	279.9	174.8	612.9
2001	0.130	125.8	0.0	11.8	0.0	137.7	2.000	148.4	127.5	5.2	281.1	168.8	587.7
2002	0.120	118.4	0.0	7.8	0.0	126.4	2.000	150.5	127.2	5.0	282.8	170.2	579.5
2003	0.100	100.7	0.0	0.0	0.0	100.7	2.000	152.6	127.0	4.8	284.5	165.1	550.4
2004	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	4.5	286.6	105.4	392.0
2005	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	4.3	286.3	106.7	393.1
2006	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	4.1	286.1	108.0	394.2
2007	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	3.9	285.9	108.0	394.0
2008	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	3.7	285.7	108.0	393.8
2009	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	3.4	285.5	108.1	393.6
2010	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	3.2	285.2	108.1	393.4
2011	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	3.0	285.0	108.1	393.2
2012	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	2.8	284.8	108.1	393.0
2013	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	2.6	284.6	108.2	392.8
2014	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	2.4	284.4	108.2	392.6
2015	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	2.1	284.2	108.2	392.4
2016	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	1.9	283.9	108.2	392.2
2017	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	1.7	283.7	108.2	392.0
2018	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	1.5	283.5	108.3	391.8
2019	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	1.3	283.3	108.3	391.6
2020	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	1.0	283.1	108.3	391.4
2021	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	0.8	282.8	108.3	391.2
2022	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	0.6	282.6	108.3	391.0
2023	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	0.4	282.4	108.4	390.8
2024	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	0.2	282.2	108.4	390.6
2025	0.000	0.0	0.0	0.0	0.0	0.0	1.000	77.5	63.4	0.0	141.0	49.5	190.5
2026	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0
	7,641T	13,570	9,042	1,109	9	20,732	29,565T	6,104	5,154	184	11,443	11,309	46,485

CUMULATIVE TOTALS

AGO 533118

ALASKA STATE REVENUES
(MILLIONS OF DOLLARS)

YEAR	OIL PRODUCTION PROD RATE MMBL/DAY	OIL ROYALTY PAYMENT	OIL SEVERANCE TAX	OIL PROPERTY TAX	OIL CONSERV. TAX	OIL TOTAL	GAS PRODUCTION PROD RATE MMMCF/DAY	GAS ROYALTY PAYMENT	GAS SEVERANCE TAX	GAS PROPERTY TAX	GAS TOTAL	STATE INCOME TAX	TOTAL STATE RETURN
1977	1.050	191.6	187.7	36.0	0.4	415.9	0.000	0.0	0.0	0.0	0.0	0.0	415.9
1978	1.425	330.0	382.2	37.9	0.6	810.9	0.000	0.0	0.0	0.0	0.0	197.2	1,008.2
1979	1.500	633.0	603.1	40.0	0.6	1,276.8	0.000	0.0	0.0	0.0	0.0	333.4	1,610.2
1980	1.500	958.1	759.8	41.7	0.6	1,760.4	0.000	0.0	0.0	0.0	0.0	528.6	2,289.1
1981	1.500	977.2	755.2	45.2	0.6	1,778.5	0.000	0.0	0.0	0.0	0.0	535.3	2,313.8
1982	1.500	996.8	750.1	50.1	0.6	1,797.8	0.000	0.0	0.0	3.0	3.0	539.5	2,340.4
1983	1.500	1,016.7	744.4	57.3	0.6	1,819.2	0.000	0.0	0.0	7.5	7.5	543.6	2,370.5
1984	1.500	1,037.1	737.5	64.1	0.6	1,839.5	0.000	0.0	0.0	12.1	12.1	547.3	2,399.0
1985	1.500	1,057.8	734.5	70.4	0.6	1,863.5	2.000	155.1	108.6	17.6	281.4	676.7	2,821.7
1986	1.300	935.1	649.3	68.7	0.5	1,653.8	2.000	155.1	108.6	17.3	281.1	603.7	2,538.8
1987	1.150	843.7	581.7	66.8	0.5	1,492.9	2.000	155.1	108.6	17.0	280.8	551.7	2,325.5
1988	1.000	748.3	512.3	62.9	0.4	1,324.1	2.000	155.1	108.6	16.5	280.4	497.5	2,102.0
1989	0.760	580.1	390.6	59.0	0.3	1,030.1	2.000	155.1	108.6	16.1	279.9	400.6	1,710.7
1990	0.580	451.6	299.3	55.0	0.2	806.3	2.000	155.1	108.6	15.6	279.5	326.8	1,412.6
1991	0.420	333.5	216.6	51.1	0.1	601.5	2.000	155.1	108.6	15.2	279.0	259.1	1,139.7
1992	0.400	324.0	205.0	47.2	0.1	576.4	2.000	155.1	108.6	14.7	278.6	255.3	1,110.4
1993	0.350	289.2	176.3	43.2	0.1	508.9	2.000	155.1	108.6	14.3	278.1	236.6	1,023.8
1994	0.330	278.1	154.3	39.3	0.1	472.0	2.000	155.1	108.6	13.8	277.7	232.9	982.6
1995	0.320	275.0	129.0	35.4	0.1	439.6	2.000	155.1	108.6	13.4	277.2	234.6	951.6
1996	0.250	219.2	71.9	31.4	0.1	322.7	2.000	155.1	108.6	12.9	276.8	204.9	804.4
1997	0.210	205.7	0.0	27.5	0.1	233.3	2.000	155.1	108.6	12.5	276.3	205.5	715.2
1998	0.200	182.4	0.0	23.6	0.0	206.1	2.000	155.1	108.6	12.0	275.9	193.2	675.3
1999	0.170	158.1	0.0	19.6	0.0	177.9	2.000	155.1	108.6	11.6	275.4	180.1	633.5
2000	0.150	142.3	0.0	15.7	0.0	158.1	2.000	155.1	108.6	11.2	275.0	173.4	606.6
2001	0.130	125.8	0.0	11.8	0.0	137.7	2.000	155.1	108.6	10.7	274.5	167.6	579.9
2002	0.120	118.4	0.0	7.8	0.0	126.4	2.000	155.1	108.6	10.3	274.1	169.2	569.8
2003	0.100	100.7	0.0	0.0	0.0	100.7	2.000	155.1	108.6	9.8	273.6	164.4	538.8
2004	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	9.4	273.2	104.9	378.2
2005	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	8.9	272.7	106.3	379.1
2006	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	8.5	272.3	107.6	379.9
2007	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	8.0	271.8	107.6	379.5
2008	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	7.6	271.4	107.7	379.1
2009	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	7.1	270.9	107.7	378.7
2010	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	6.7	270.5	107.8	378.3
2011	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	6.2	270.0	107.8	377.9
2012	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	5.8	269.6	107.9	377.5
2013	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	5.3	269.1	107.9	377.1
2014	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	4.9	268.7	107.9	376.7
2015	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	4.4	268.3	108.0	376.3
2016	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	4.0	267.8	108.0	375.9
2017	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	3.5	267.4	108.1	375.5
2018	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	3.1	266.9	108.1	375.1
2019	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	2.6	266.5	108.1	374.7
2020	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	2.2	266.0	108.2	374.2
2021	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	1.7	265.6	108.2	373.8
2022	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	1.3	265.1	108.3	373.4
2023	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	0.8	264.7	108.3	373.0
2024	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	0.4	264.2	108.4	372.6
2025	0.000	0.0	0.0	0.0	0.0	0.0	1.000	77.5	54.3	0.0	131.9	49.5	181.4
2026	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0
	7,641T	13,570	9,042	1,109	9	23,732	29,565T	6,285	4,339	383	11,074	11,273	46,080

CUMULATIVE TOTALS

ADG 533119

INDUSTRY CASH FLOWS
(MILLIONS OF DOLLARS)

YEAR 1-50	* * * * * * OIL PRODUCTION * * * * * * WELLHEAD PRICE/BBL	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET OIL CASH FLOW	* * * * * * GAS PRODUCTION * * * * * * WELLHEAD PRICE/MCF	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET GAS CASH FLOW	ST. INC. TAX	FED. INC. TAX	TOTAL NET CASH FLOW
1	4.00	1533.0	415.9	103.0	122.6	891.4	1.95	0.0	0.0	26.0	0.0	-26.0	0.0	259.6	605.7
2	6.00	3120.7	810.9	140.0	161.9	2007.8	1.95	0.0	0.0	33.0	0.0	-33.0	197.2	533.2	1244.3
3	9.25	5064.3	1276.8	156.0	187.4	3444.0	1.95	0.0	0.0	32.0	0.0	-32.0	333.4	923.6	2155.0
4	14.00	7665.0	1760.4	163.0	290.6	5450.9	1.95	0.0	0.0	36.0	0.0	-36.0	528.6	1465.8	3420.3
5	14.28	7818.3	1778.5	171.0	369.0	5499.7	1.95	0.0	0.0	41.0	92.6	-133.6	535.3	1449.2	3381.5
6	14.56	7974.6	1797.8	173.0	511.9	5491.8	1.95	0.0	3.0	48.0	148.5	-199.6	539.5	1425.8	3326.8
7	14.85	8134.1	1819.2	174.0	590.3	5550.4	1.95	0.0	7.5	54.0	172.8	-234.3	543.6	1431.7	3340.7
8	15.15	8295.8	1839.5	178.0	668.8	5610.5	1.95	0.0	12.1	60.0	235.1	-307.2	547.3	1426.7	3329.1
9	15.45	8462.7	1863.5	230.0	462.7	5906.4	1.95	1535.1	281.4	102.0	104.9	953.6	676.7	1855.0	4328.3
10	15.76	7481.0	1653.8	210.0	476.3	5140.8	1.95	1532.1	281.1	212.0	104.7	934.2	603.7	1641.3	3829.9
11	16.08	6750.2	1492.9	195.0	378.3	4683.9	1.95	1532.1	280.8	219.0	95.2	937.0	551.7	1520.7	3548.4
12	16.40	5087.1	1324.1	181.0	370.3	4111.7	1.95	1532.1	280.4	193.0	93.1	965.5	497.5	1373.9	3205.8
13	16.73	4641.2	1030.1	157.0	362.3	3091.7	1.95	1532.	279.9	192.0	91.1	969.0	400.6	1038.0	2562.1
14	17.06	3612.8	806.3	133.0	354.2	2313.2	1.95	1532.1	279.5	192.0	87.6	972.9	326.8	887.8	2071.5
15	17.40	2668.5	601.5	123.0	346.2	1597.6	1.95	1532.1	279.0	192.0	84.2	976.8	259.1	694.6	1620.7
16	17.75	2592.2	576.4	121.0	338.2	1556.5	1.95	1532.1	278.6	192.0	82.3	979.1	255.3	684.1	1596.2
17	18.11	2313.6	508.9	116.0	330.2	1358.4	1.95	1532.	278.1	192.0	80.4	981.5	236.6	630.9	1472.2
18	18.47	2225.0	472.0	115.0	322.2	1315.8	1.95	1532.1	277.7	192.0	78.5	983.9	232.9	620.0	1446.7
19	18.84	2200.7	439.6	114.0	314.1	1332.9	1.95	1532.1	277.2	192.0	76.6	986.2	234.6	625.3	1459.1
20	19.21	1753.7	322.7	107.0	306.1	1017.8	1.95	1532.1	276.8	192.0	74.6	988.6	204.9	540.4	1261.0
21	19.60	1645.7	283.3	105.0	283.6	1023.6	1.95	1532.1	276.3	192.0	72.7	990.9	205.5	542.7	1266.3
22	19.99	1459.6	206.1	102.0	259.7	891.7	1.95	1532.1	275.9	192.0	70.8	993.3	193.2	507.5	1184.3
23	20.39	1265.5	177.9	99.0	236.3	752.2	1.95	1532.1	275.4	192.0	68.9	995.7	180.1	470.3	1097.4
24	20.80	1138.9	158.1	97.0	204.1	679.6	1.95	1532.1	275.0	192.0	67.0	998.0	173.4	451.2	1052.9
25	21.21	1006.8	137.7	95.0	168.2	605.9	1.95	1532.1	274.5	192.0	54.2	1011.3	167.6	434.8	1014.6
26	21.64	947.9	126.4	94.0	121.7	605.8	1.95	1532.1	274.1	192.0	37.1	1028.8	169.2	439.6	1025.7
27	22.07	805.7	100.7	92.0	74.7	538.3	1.95	1532.1	273.6	192.0	20.6	1045.8	164.4	425.9	993.8
28	22.51	0.0	0.0	200.0	27.4	-227.4	1.95	1532.1	273.2	192.0	0.0	1066.9	104.9	220.3	514.1
29	22.96	0.0	0.0	100.0	13.5	-113.5	1.95	1532.1	272.7	192.0	0.0	1067.3	106.3	254.2	593.2
30	23.42	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	272.3	192.0	0.0	1067.7	107.6	288.0	672.1
31	23.89	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	271.8	192.0	0.0	1068.2	107.6	288.1	672.3
32	24.37	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	271.4	192.0	0.0	1068.6	107.7	288.2	672.6
33	24.86	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	270.9	192.0	0.0	1069.1	107.7	288.4	672.9
34	25.35	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	270.5	192.0	0.0	1069.5	107.8	288.5	673.2
35	25.86	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	270.0	192.0	0.0	1070.0	107.8	288.6	673.5
36	26.38	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	269.6	192.0	0.0	1070.4	107.9	288.7	673.8
37	26.91	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	269.1	192.0	0.0	1070.9	107.9	288.8	674.0
38	27.44	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	268.7	192.0	0.0	1071.3	107.9	289.0	674.3
39	27.99	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	268.3	192.0	0.0	1071.8	108.0	289.1	674.6
40	28.55	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	267.8	192.0	0.0	1072.2	108.0	289.2	674.9
41	29.12	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	267.4	192.0	0.0	1072.7	108.1	289.3	675.2
42	29.71	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	266.9	192.0	0.0	1073.1	108.1	289.5	675.5
43	30.30	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	266.5	192.0	0.0	1073.6	108.1	289.6	675.7
44	30.91	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	266.0	192.0	0.0	1074.0	108.2	289.7	676.0
45	31.53	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	265.6	192.0	0.0	1074.5	108.2	289.8	676.3
46	32.16	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	265.1	192.0	0.0	1074.9	108.3	289.9	676.6
47	32.80	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	264.7	192.0	0.0	1075.4	108.3	290.1	676.9
48	33.46	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	264.2	192.0	0.0	1075.8	108.4	290.2	677.2
49	34.12	0.0	0.0	0.0	0.0	0.0	1.95	766.0	131.9	96.0	0.0	538.1	49.5	146.5	342.0
50	34.81	0.0	0.0	0.0	0.0	0.0	1.95	0.0	0.0	100.0	0.0	-100.0	0.0	0.0	-100.0
		108,567	23,732	4,050	8,654	72,130		62,051	11,074	8,335	2,094	40,628	11,273	30,475	71,009

CUMULATIVE TOTALS

AGO 533120

ALASKA STATE REVENUES
(MILLIONS OF DOLLARS)

Run 17

YEAR	****** OIL PRODUCTION ****** PROD RATE MBBL/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	CONSERV. TAX	OIL TOTAL	****** GAS PRODUCTION ****** PROD RATE MMCF/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	GAS TOTAL	STATE INCOME TAX	TOTAL STATE RETURN
1977	1.050	191.6	187.7	36.0	0.4	415.9	0.000	0.0	0.0	0.0	0.0	0.0	415.9
1978	1.425	390.0	382.2	37.9	0.6	810.9	0.000	0.0	0.0	0.0	0.0	197.2	1,008.2
1979	1.500	633.0	603.1	40.0	0.6	1,276.8	0.000	0.0	0.0	0.0	0.0	333.4	1,610.2
1980	1.500	958.1	759.8	41.7	0.6	1,760.4	0.000	0.0	0.0	0.0	0.0	528.6	2,289.1
1981	1.500	977.2	755.2	45.2	0.6	1,778.5	0.000	0.0	0.0	0.0	0.0	535.3	2,313.8
1982	1.500	936.8	750.1	50.1	0.6	1,737.8	0.000	0.0	0.0	0.9	0.9	539.7	2,338.5
1983	1.500	1,016.7	744.4	57.3	0.6	1,819.2	0.000	0.0	0.0	2.5	2.5	544.1	2,365.9
1984	1.500	1,037.1	737.5	64.1	0.6	1,839.5	0.000	0.0	0.0	4.3	4.3	548.0	2,391.9
1985	1.500	1,057.8	734.5	70.4	0.6	1,863.5	2.000	142.0	99.4	6.7	248.2	678.9	2,790.8
1986	1.300	935.1	649.3	68.7	0.5	1,653.8	2.000	142.1	99.4	7.5	249.1	605.9	2,508.9
1987	1.150	843.7	581.7	66.8	0.5	1,492.9	2.000	143.2	100.3	8.3	251.9	553.7	2,298.5
1988	1.000	748.3	512.3	62.9	0.4	1,324.1	2.000	143.5	100.4	8.0	252.1	499.4	2,075.6
1989	0.760	580.1	390.6	59.0	0.3	1,030.1	2.000	143.8	100.6	7.8	252.3	402.4	1,684.9
1990	0.580	451.6	299.3	55.0	0.2	806.3	2.000	144.2	100.9	7.6	252.8	328.6	1,387.8
1991	0.420	333.5	216.6	51.1	0.1	601.5	2.000	144.6	101.2	7.4	253.3	260.8	1,115.7
1992	0.400	324.0	205.0	47.2	0.1	576.4	2.000	144.9	101.4	7.2	253.5	257.0	1,087.0
1993	0.350	289.2	176.3	43.2	0.1	508.9	2.000	145.1	101.5	6.9	253.7	238.3	1,001.0
1994	0.330	278.1	154.3	39.3	0.1	472.0	2.000	145.3	101.7	6.7	253.9	234.4	960.4
1995	0.320	275.0	129.0	35.4	0.1	439.6	2.000	145.6	101.9	6.5	254.1	236.2	929.9
1996	0.250	219.2	71.9	31.4	0.1	322.7	2.000	145.8	102.1	6.3	254.3	206.4	783.4
1997	0.230	205.7	0.0	27.5	0.1	233.3	2.000	146.1	102.2	6.1	254.4	207.0	694.8
1998	0.200	182.4	0.0	23.6	0.0	206.1	2.000	146.3	102.4	5.9	254.6	194.6	655.4
1999	0.170	158.1	0.0	19.6	0.0	177.9	2.000	146.5	102.6	5.6	254.8	181.5	614.3
2000	0.150	142.3	0.0	15.7	0.0	158.1	2.000	146.8	102.7	5.4	255.0	174.8	588.0
2001	0.130	125.8	0.0	11.8	0.0	137.7	2.000	148.4	103.8	5.2	257.5	168.8	564.1
2002	0.120	118.4	0.0	7.8	0.0	126.4	2.000	150.5	105.3	5.0	260.9	170.2	557.5
2003	0.100	100.7	0.0	0.0	0.0	100.7	2.000	152.6	106.8	4.8	264.2	165.1	530.1
2004	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	4.5	268.4	105.4	373.8
2005	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	4.3	268.1	106.7	374.9
2006	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	4.1	267.9	108.0	376.0
2007	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	3.9	267.7	108.0	375.8
2008	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	3.7	267.5	108.0	375.6
2009	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	3.4	267.3	108.1	375.4
2010	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	3.2	267.0	108.1	375.2
2011	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	3.0	266.8	108.1	375.0
2012	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	2.8	266.6	108.1	374.8
2013	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	2.6	266.4	108.2	374.6
2014	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	2.4	266.2	108.2	374.4
2015	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	2.1	266.0	108.2	374.2
2016	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	1.9	265.7	108.2	374.0
2017	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	1.7	265.5	108.2	373.8
2018	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	1.5	265.3	108.3	373.6
2019	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	1.3	265.1	108.3	373.4
2020	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	1.0	264.9	108.3	373.2
2021	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	0.8	264.6	108.3	373.0
2022	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	0.6	264.4	108.3	372.8
2023	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	0.4	264.2	108.4	372.6
2024	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	0.2	264.0	108.4	372.4
2025	0.000	0.0	0.0	0.0	0.0	0.0	1.000	77.5	54.3	0.0	131.9	49.5	181.4
2026	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0
	7,641T	13,570	9,042	1,103	9	23,732	29,565T	6,104	4,273	184	10,561	11,309	45,603

CUMULATIVE TOTALS

AOG 533121

INDUSTRY CASH FLOWS
(MILLIONS OF DOLLARS)

YEAR 1-50	****** OIL PRODUCTION ****** WELLHEAD PRICE/BBL	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET OIL CASH FLOW	****** GAS PRODUCTION ****** WELLHEAD PRICE/MCF	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET GAS CASH FLOW	ST. INC. TAX	FED. INC. TAX	TOTAL NET CASH FLOW
1	4.00	1533.0	415.9	103.0	122.6	891.4	1.95	0.0	0.0	26.0	0.0	-26.0	0.0	259.6	605.7
2	8.00	3120.7	810.9	140.0	161.9	2007.8	1.95	0.0	0.0	33.0	0.0	-33.0	197.2	533.2	1244.3
3	9.25	5064.3	1276.8	156.0	187.4	3444.0	1.95	0.0	0.0	32.0	0.0	-32.0	333.4	923.6	2155.0
4	14.00	7665.0	1760.4	163.0	290.6	5450.9	1.95	0.0	0.0	36.0	0.0	-36.0	528.6	1465.8	3420.3
5	14.28	7810.3	1778.5	171.0	369.0	5499.7	1.95	0.0	0.0	41.0	92.6	-133.6	535.3	1449.2	3381.5
6	14.56	7974.6	1797.8	173.0	511.9	5491.8	1.95	0.0	0.9	48.0	148.5	-197.5	539.7	1426.3	3328.2
7	14.85	8134.1	1819.2	174.0	590.3	5550.4	1.95	0.0	2.5	54.0	172.8	-229.3	544.1	1433.1	3343.9
8	15.15	8295.8	1839.5	178.0	668.8	5610.5	1.95	0.0	4.3	60.0	275.1	-299.5	548.0	1428.8	3334.0
9	15.45	8462.7	1863.5	230.0	462.7	5906.4	1.95	1522.9	248.2	192.0	104.9	977.6	678.9	1861.5	4343.5
10	15.76	7481.0	1653.8	210.0	476.3	5140.8	1.95	1522.9	249.1	212.0	104.7	957.0	605.9	1647.6	3844.4
11	16.08	6750.2	1492.9	195.0	378.3	4683.9	1.95	1523.8	251.9	219.0	95.2	957.6	553.7	1526.3	3561.5
12	16.40	5087.1	1324.1	181.0	370.3	4111.7	1.95	1523.9	252.1	193.0	93.1	985.6	499.4	1379.3	3218.5
13	16.73	4641.2	1030.1	157.0	362.3	3091.7	1.95	1524.1	252.3	192.0	91.1	988.6	402.4	1103.3	2574.5
14	17.06	3612.8	806.3	139.0	354.2	2313.2	1.95	1524.4	252.8	192.0	87.6	991.9	328.6	892.9	2083.5
15	17.40	2648.5	601.5	123.0	346.2	1597.6	1.95	1524.7	253.3	192.0	84.2	995.1	260.8	699.5	1632.3
16	17.75	2592.2	576.4	121.0	338.2	1556.5	1.95	1524.9	253.5	192.0	82.3	997.0	257.0	688.9	1607.5
17	18.11	2313.6	508.9	116.0	330.2	1358.4	1.95	1525.0	253.7	192.0	80.4	998.9	238.3	635.7	1483.3
18	18.47	2225.0	472.0	115.0	322.2	1315.8	1.95	1525.2	253.9	192.0	78.5	1000.8	234.4	624.6	1457.5
19	18.84	2200.7	439.6	114.0	314.1	1332.9	1.95	1525.4	254.1	192.0	76.6	1002.7	236.2	629.8	1469.5
20	19.21	1753.7	322.7	107.0	306.1	1017.8	1.95	1525.6	254.3	192.0	74.6	1004.6	206.4	544.8	1271.2
21	19.60	1645.7	233.3	105.0	283.6	1023.6	1.95	1525.7	254.4	192.0	72.7	1006.4	207.0	546.9	1276.1
22	19.99	1450.6	206.1	102.0	259.7	891.7	1.95	1525.9	254.6	192.0	70.8	1008.3	194.6	511.6	1193.8
23	20.39	1265.5	177.9	99.0	236.3	752.2	1.95	1526.1	254.8	192.0	68.9	1010.2	181.5	474.3	1106.7
24	20.80	1138.9	158.1	97.0	204.1	679.6	1.95	1526.2	255.0	192.0	67.0	1012.1	174.8	455.0	1061.8
25	21.21	1008.8	137.7	95.0	168.2	605.9	1.95	1527.3	257.5	192.0	54.2	1023.6	168.8	438.2	1022.4
26	21.64	947.9	126.4	94.0	121.7	605.8	1.95	1528.8	260.9	192.0	37.1	1038.7	170.2	442.3	1032.0
27	22.07	805.7	100.7	92.0	74.7	538.3	1.95	1530.3	264.2	192.0	20.6	1053.4	165.1	427.9	998.6
28	22.51	0.0	0.0	200.0	27.4	-227.4	1.95	1532.1	268.4	192.0	0.0	1071.7	105.4	221.6	517.2
29	22.96	0.0	0.0	100.0	13.5	-113.5	1.95	1532.1	268.1	192.0	0.0	1071.9	106.7	255.5	596.1
30	23.42	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	267.9	192.0	0.0	1072.1	108.0	289.2	674.8
31	23.89	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	267.7	192.0	0.0	1072.3	108.0	289.2	675.0
32	24.37	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	267.5	192.0	0.0	1072.5	108.0	289.3	675.1
33	24.85	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	267.3	192.0	0.0	1072.8	108.1	289.4	675.2
34	25.35	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	267.0	192.0	0.0	1073.0	108.1	289.4	675.4
35	25.86	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	266.8	192.0	0.0	1073.2	108.1	289.5	675.5
36	26.38	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	266.6	192.0	0.0	1073.4	108.1	289.5	675.7
37	26.91	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	266.4	192.0	0.0	1073.6	108.2	289.6	675.8
38	27.44	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	266.2	192.0	0.0	1073.9	108.2	289.7	675.9
39	27.99	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	266.0	192.0	0.0	1074.1	108.2	289.7	676.1
40	28.55	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	265.7	192.0	0.0	1074.3	108.2	289.8	676.2
41	29.12	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	265.5	192.0	0.0	1074.5	108.2	289.8	676.3
42	29.71	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	265.3	192.0	0.0	1074.7	108.3	289.9	676.5
43	30.30	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	265.1	192.0	0.0	1075.0	108.3	290.0	676.6
44	30.91	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	264.9	192.0	0.0	1075.2	108.3	290.0	676.8
45	31.53	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	264.6	192.0	0.0	1075.4	108.3	290.1	676.9
46	32.16	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	264.4	192.0	0.0	1075.6	108.3	290.1	677.0
47	32.80	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	264.2	192.0	0.0	1075.8	108.4	290.2	677.2
48	33.46	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	264.0	192.0	0.0	1076.0	108.4	290.2	677.3
49	34.12	0.0	0.0	0.0	0.0	0.0	1.95	766.0	131.9	96.0	0.0	538.1	49.5	146.5	342.0
50	34.81	0.0	0.0	0.0	0.0	0.0	1.95	0.0	0.0	100.0	0.0	-100.0	0.0	0.0	-100.0
		108,567	23,732	4,050	8,654	72,130		61,924	10,561	8,335	2,094	41,014	11,309	30,580	71,254

CUMULATIVE TOTALS

AGO 533122

STATE OF ALASKA

OIL AND GAS CONSERVATION COMMISSION

THREE DIMENSIONAL RESERVOIR STUDY SADLEROCHIT FORMATION PRUDHOE BAY FIELD

Legislative Reference Library
Legislative Affairs Agency
Pouch Y State Capitol
Juneau, Alaska 99811

MARCH, 1980

AGO 533123

THREE-DIMENSIONAL RESERVOIR STUDY
SADLEROCHIT FORMATION
PRUDHOE BAY FIELD

Prepared for

STATE OF ALASKA
JAY S. HAMMOND, GOVERNOR
ALASKA OIL AND GAS CONSERVATION COMMISSION
Hoyle H. Hamilton, Chairman
Harry W. Kugler
Lonnie C. Smith

by

H. K. van Poollen and Associates, Inc.

March 1980

H. K. VAN POOLLEN AND ASSOCIATES, INC.
1100 WEST LITTLETON BOULEVARD LITTLETON, COLORADO 80120
TELEPHONE: 303 795-8578
TWX: 910 935 0102 ANS: HKVANPOOL LITL

AGO 533124

TABLE OF CONTENTS

	Page No.
LIST OF TABLES	iii
LIST OF FIGURES	iv
LIST OF EXHIBITS	v
ACKNOWLEDGEMENT	vi
INTRODUCTION	1
CONCLUSIONS	1
RECOMMENDATIONS	2
LIMITATION	2
BOUNDARY CONDITIONS	3
In-Place Volumes	3
Ratios	3
Productivity Index	4
Pressure	4
Injection	4
Wells	5
INPUT DATA	5
HO-T Zone	5
Aquifer	6
Faults	6
Shales	6
Permeability	6
Relative Permeability	7
Water Compressibility	8
Rock Compressibility	8
Pressure-Volume-Temperature (PVT)	8
Individual Well Data	8
Pressure Build-Up	8
RESERVOIR MODELING	8
Cross Sections	9
Three Dimensional	10
INDIVIDUAL RUNS	10
EFFECTS OF GAS CYCLING AND CONING	11
TABLES	
FIGURES	
EXHIBITS	

AGO 533125

LIST OF TABLES

No.	
I	Original Hydrocarbons In-Place, Sadlerochit Formation Prudhoe Bay Field
II	Recompletion Schedule for Cases A, B, C, D, Prudhoe Bay Field

AGO 533126

LIST OF FIGURES

No.	
1	Two Phase Relative Permeability, k_{ro} and k_{rw} vs S_w
2	Two Phase Relative Permeability, k_{rg} and k_{rL} vs S_L
3	Oil PVT Table #1, Oil Properties vs Pressure
4	Oil PVT Table #2, Oil Properties vs Pressure
5	Gas PVT Table #1, Gas Properties vs Pressure
6	Three Dimensional Grid
7	Cross-Section Model Locations
8	Cell to Cell Relative Permeability, k_{rg} and k_{rL} vs S_L
9	Individual Well Relative Permeability, k_{rg} and k_{rL} vs S_L
10	Schematic Representation of Cases A, B, C and D
11	Prediction vs Time, Case A
12	Prediction vs Time, Case A (Cumulative)
13	Prediction vs Oil Recovery, Case A
14	Prediction vs Time, Case B
15	Prediction vs Time, Case B (Cumulative)
16	Prediction vs Oil Recovery, Case B
17	Prediction vs Time, Case C
18	Prediction vs Time, Case C (Cumulative)
19	Prediction vs Oil Recovery, Case C
20	Prediction vs Time, Case D
21	Prediction vs Time, Case D (Cumulative)
22	Prediction vs Oil Recovery, Case D

AGO 533127

LIST OF EXHIBITS

No.	
A	North-South Cross Section
B	East-West Cross Section

AGO 533128

ACKNOWLEDGEMENT

This study was performed under contract for and in cooperation with the Alaska Oil and Gas Conservation Commission, State of Alaska. Data were made available by operators in the field for the purpose of this overall field-wide performance study.

H. K. van Poollen
H. K. van Poollen and Associates, Inc.

Joseph P. Green, Reservoir Engineer
and Project Director for
State of Alaska

AGO 533129

INTRODUCTION

This report describes the results of a three-dimensional (3-D) model study of the Sadlerochit Formation of the Prudhoe Bay Field. The objectives of the study were to determine the effect on ultimate oil recovery of:

1. A source water injection program.
2. Reservoir gas voidage of 2.7 billion cubic feet per day (2.0 billion cubic feet available for sales).

The available reservoir data included:

Individual well completion data
Production rate data
Pressure data
Core analyses
Well logs

All data were originally released by the operators to the State of Alaska Oil and Gas Conservation Commission. The cutoff for most historical data was June 1979, however production figures were matched to August 1979. Using current volumetric data, the 1974 oil-in-place and gas-in-place volumes were updated as indicated in Table I. Next a three-dimensional, three-phase reservoir model was used to study the reservoir performance under various producing plans.

CONCLUSIONS

1. Oil recovery can be substantially increased by effective source water injection. For the cases studied, an average increased recovery of 1.5 billion barrels (1.1 to 1.9), representing an average difference in recovery of 7.4% of the stock tank oil-in-place (5.3% to 9.5%), may be attributed to source water injection.
2. Gas voidage of 2.7 billion cubic feet per day in the presence of source water injection should not materially affect ultimate oil recovery. Differences in recovery varied between 0.4% and 0.7% (0.08 to 0.14 billion barrels). These small variations are considered to be less than the average range of comparison sensitivity of the model.

3. Since all comparisons showed greater ultimate recovery with source water injection, it should be implemented as soon as feasible.
4. Ultimate oil recoveries range from 36% to 46% of the original-oil-in-place (O.O.I.P.). The low value was from a case without source water injection or optimized recompletions in the later field life. The high value was with source water injection and assumed no gas coning or adverse permeability variations.
5. While the boundary conditions were limited because of budget and time constraints they were sufficient to accomplish the basic study objectives.

RECOMMENDATIONS

Now that the State has a working 3-D model, additional studies should be made which include:

1. Different values of oil production rate, gas production rate and source water injection rate.
2. Updating the model using new production data, well data (logs, etc.) and pressures.
3. Monitoring field behavior.
4. Further study of the possible effects of gas coning/fingering and adverse permeability variations on ultimate recovery.
5. Fine-grid simulation to evaluate alternate injection patterns, shale effects, and well MER (maximum efficient rate).
6. Capillary pressure values in shaley areas.
7. The effects of lower producing bottom-hole pressures and different well densities.
8. The effects of source water injection into the gas cap.
9. The effect of increased gas recycling.

LIMITATION

Generally, accurate forecasting is limited to two or three times the actual production history. A data cutoff point of August 1, 1979 meant only 790 days of actual production history, or less than 2,000 days of effective prediction (five years). In the case of Prudhoe Bay, this effective prediction period may be longer because of the excellent

nature of well data and density of wells. Even so, the ultimate recovery indicated for any group of comparative cases run may have a tolerance of as much as 5% of the O.O.I.P. (i.e., an indicated recovery of 40% might be as low as 35% or as high as 45%). The low range of production might be due to erroneous end values on relative permeability, coning and/or fingering effects, and adverse permeability variations. The high range might be due to better reservoir continuity, more favorable mobility and benefits of gas cycling. Nevertheless, the relative recoveries of the different processes should be valid (i.e., source water injection versus no source water injection and the relative effect of gas sales). Ultimate recovery estimates may vary as more history is gained and additional data become available from full field development. Conditions which might affect a change would affect comparative cases proportionately so that the conclusions remain valid.

The shale descriptions in the model are coarse, and a more detailed refinement is necessary for precise understanding of fingering and coning. Shale members in the eastern portion of the field sometimes occur more closely spaced than the vertical dimension of the grid blocks. This had to be accounted for mathematically as indicated on page 6.

BOUNDARY CONDITIONS

In-Place Volumes

In order to have a basis for comparing the cases, certain parameters were fixed. The original hydrocarbons in-place are 20.6 billion barrels of stock tank oil, 14.9 trillion standard cubic feet of solution gas and 23.4 trillion standard cubic feet of gas cap gas. The maximum field offtake rate was set at 1.5 million barrels of stock tank oil (STO) per day.

Ratios

Individual wells were allowed to produce at gas-oil ratios up to 100,000 cubic feet per barrel. This gas-oil ratio limit was not the major boundary condition as gas production limitation was prorated

based on the actual maximum field gas handling capacity. It was assumed for all cases that 10% of the gas produced would be utilized as fuel for lease and pipeline operations. For the no-gas-sales cases, the remaining 90% of all produced gas was returned to the gas cap. The water-oil ratio limitation for individual wells was set at twenty barrels of water per barrel of stock tank oil, but was never reached because of the pronounced effect of three-phase relative permeability. In all cases, the field was shut-in when the total oil producing rate had declined to 100,000 barrels stock tank oil per day.

When applicable, gas voidage rates were set at 2.7 billion standard cubic feet of gas per day and started in mid-1985.

Productivity Index

Existing wells were assigned actual values for productivity index (PI). For a well with a full oil column this value ranged from less than 5 to over 100 with an average of 14.6 barrels per day per psi. For wells with less oil column a value of 3.65 was assigned to each "exposed" grid interval. All new wells were assigned this average value for each exposed layer.

Pressure

The minimum producing bottom-hole pressure for all wells was set at 2,000 psi. This was intended to simulate using artificial lift and a low pressure gathering system. There may be a possibility of reducing this to 1,500 psi which would improve ultimate recovery and could affect producing gas-oil ratios. Further work is needed in this regard.

Injection

In each case, all produced water was reinjected into peripheral water injection wells starting in mid-1981 and source water, where applicable, was initiated in mid-1984. While the number of produced water injection wells was increased as necessary to accommodate the produced water volume, all source water injection wells were activated in mid-1984. For the cases which had source water injection, it was limited to a maximum injection rate of two million barrels per day, or a maximum reservoir pressure of 3,950 psi.

Wells

Producing wells were located on 160-acre spacing and generally had multiple intervals exposed. Injection wells were also on 160-acre spacing located above the heavy oil-tar zone (HO-T) with single interval completions.

INPUT DATA

The volumetric determination of oil- and gas-in-place was updated from the 1974 report using data from wells logged through the end of 1978. The same approach was used as in the 1974 report and the comparisons are depicted in Table I.

HO-T Zone

The heavy oil-tar zone (HO-T) has been discussed in prior reports. Because of the high viscosity of the oil in this zone it will probably result in higher residual oil saturations and adversely affect the relative permeability to water.

In this study the HO-T zone was represented as having an average thickness of 50 ft ranging from 8,990 to 9,040 ft, a total oil-in-place volume of 1.9 billion barrels, a residual oil saturation of 40%, a reduced relative permeability to water by a factor of 10, and an increased oil viscosity by a factor of 10. The oil recovery from this interval is essentially zero.

Both operators conducted independent water injectivity tests which confirmed high injectivity into both the light oil and aquifer intervals but poor injectivity into the HO-T interval. It was determined that sufficient injection water could be passed through the HO-T interval to allow effective peripheral flooding from aquifer injection, barrier faults along the western field boundary precluded its use in that area. This, together with the more realistic response time of "in zone" injection, led us to place all water injection intervals above the HO-T zone.

Aquifer

Based on previous studies and field observation, the aquifer is only slightly effective. A 1.7 trillion barrel aquifer was used in this model.

Faults

The field has been cut by several vertical faults. Where these faults appear to be fluid barriers they were simulated in the model as a plane of zero horizontal transmissibility.

Shales

An extensive study by the operators gave an excellent description of shales. This study, together with work done by the A.O.G.C.C. geological staff aided in the simulation of the shales. The thickness of the grid blocks used in this study varied. All thicknesses were in excess of 30 ft while shales were found as closely spaced as 5 ft. The mathematics of the model dictate that all shales had to be moved to their respective grid block boundary (either up or down, whichever was closer). Hence, our grid block dimensions may have been too coarse to truly evaluate detailed fingering. We found that, in general, when shales were present, the vertical permeabilities of the shale should be reduced by a factor of 0.01 times the vertical permeability of the adjacent sands. In some instances, this was modified based on relative shale strengths in individual grid blocks and ranged from 0.02 for blocks with partial single shales to 0.003 for blocks with multiple shales. On the east side of the field where the shales are thicker and more extensive, a vertical permeability of zero was sometimes used.

For those blocks without measured shale values (either no well present or no log available), a contour method was devised for estimation of these data.

Permeability

The permeability within each grid block was determined from both pressure build-up curves and core analyses. Individual core plugs show that vertical permeability is about 0.5 times the horizontal

permeability. On the basis of permeability variation, vertical permeability in the presence of thin shale lamanae is reduced. The vertical permeability value of 0.35 times the horizontal permeability was used throughout.

Pressure build-up curves were evaluated for both radial and spherical flow and shale breaks. Calculated values were corrected for saturation effects prior to introduction into the model.

A statistical approach was used to determine the values for the undrilled grids. Permeability values for wells having data were posted on a map. In areas of adequate representation of data derived from build-up tests, a ten point average was taken. This enabled assignment of permeability values to surrounding grid blocks. In areas where actual data were limited, one average value determined from the available data was used.

Relative Permeability

A thorough review and analysis of two-phase relative permeability data resulted in selecting the values shown in Figures 1 and 2.

Three-phase relative permeability was determined by the model using the Modified Stone's* Formula shown below:

$$k_{ro} = k_{ro_{cw}} \left[\left(\frac{k_{row}}{k_{ro_{cw}}} + k_{rw} \right) \left(\frac{k_{rog}}{k_{ro_{cw}}} + k_{rg} \right) - \left(k_{rw} + k_{rg} \right) \right]$$

where:

k_{ro} = relative permeability to oil in the presence of both gas and water

k_{row} = relative permeability to oil in the presence of water

k_{rw} = relative permeability to water

k_{rog} = relative permeability to oil in the presence of gas

*Dietrich, J.K., and Bonder, P.L., "Three-Phase Oil Relative Permeability Models," preprint of SPE 6044, presented at the 51st Annual Fall Meeting of SPE, October 3 - 6, 1976, New Orleans, LA.

k_{rg} = relative permeability of gas

$k_{ro_{cw}}$ = relative permeability to oil at connate water saturation

Water Compressibility

An average water compressibility value of 3.3×10^{-6} per psi was used.

Rock Compressibility

An average rock compressibility value of 3.4×10^{-6} per psi was used.

Pressure-Volume-Temperature (PVT)

The possibility exists that PVT properties may vary both vertically and horizontally. For the purpose of this study, only the vertical variation was considered and is shown in Figures 3, 4 and 5.

Individual Well Data

Perforated intervals and shale breaks were graphically compared. Productivity indices were determined for all existing wells and assigned to the appropriate intervals. New wells or recompletions were assigned a value of 3.65 barrels per day per psi for each grid-interval exposed.

Pressure Build-Up

A total of 249 pressure build-up tests was analyzed to determine reservoir pressure and permeability. These tests were distributed over 137 wells. The method used by the authors gave values that compared favorably with static pressure tests and with core measured permeability values.

RESERVOIR MODELING

The approach was to model the field with six layers generally in vertical communication. The modeling blocks were 160 acres throughout the oil-bearing portion of the field and were gradually increased to a

maximum of 2,560 acres in the far corners of the aquifer and gas cap. This eventually resulted in a 52 x 23 x 6 model containing 4,858 active and 2,318 passive grid blocks as shown in Figure 6.

The objective was to match the 26 months of reservoir performance and to make reservoir and individual well forecasts under different sets of producing conditions.

Empirical functions for relative permeability, capillary pressure and vertical permeability were derived using fine- and coarse-grid cross sections to adjust for numerical dispersion effects.

Cross Sections

Two major cross sections were made, as indicated in Figure 7. The fine-grid cross sections are depicted on Exhibits A and B. The cells below shale breaks were assigned a partially segregated relative permeability curve.

Shales were represented as reductions in vertical permeability as described on page 6. Modifications in horizontal permeabilities had very little or no effect on trying to duplicate gas fingering. Eventually the right combination of values was found and the NS cross section was matched. This combination was then used in the EW section and a nearly instantaneous match was obtained.

Once a match was obtained on the fine-grid cross sections, a forecast was made for each cross section. Future well rates were assumed to be equal to the last rates. Some additional runs were performed with these fine-grid cross sections using water injection and gas sales. These forecasts then became the artificial history for the derivation of the model modifiers using coarse-grid cross sections.

The coarse-grid sections (indicated by the heavy lines on Exhibits A and B) have the same dimensions as were used in the oil column of the 3-D model (i.e., six layers and 160 acres). To obtain a match for the artificial history from the fine-grid sections, the following parameters were modified:

1. Cell to cell relative permeability
2. Individual well relative permeability to represent the limited perforated intervals, perforation standoff from fluid contacts and coning or fingering effects

3. Capillary pressure
4. Vertical permeability to represent shales.

The first two functions are shown in Figures 8 and 9. Functions and their modifications were deliberately kept simple to allow for a random use in the 3-D work.

Three Dimensional

The 3-D network was assigned all reservoir functions derived from the coarse-grid cross sections in addition to the general input data. Next, individual wells, or in some instances clusters of wells, were matched. Basically, the only modifications were in the change of assigned shales in areas of lesser control. In some instances, well relative permeabilities were modified.

After the 3-D history match was obtained, forecasts were made using a predicted drilling schedule which would allow for full field development attempting to use the same general guidelines used by the operators. The new wells were assigned similar relative permeability curves as the wells which were producing during the history match.

During the forecast, wells were recompleted as follows. When gas-oil ratio from a layer reached 100,000 cubic feet per barrel, that layer and all layers above it were shut-in. After all layers of a well were shut-in, that well was reviewed for recompletion by opening those layers having sufficient oil saturation for further production. Table II shows a schedule of this type of recompletion. A similar shut-in process was used for high water-oil ratios; however, this did not become a problem as wells were not shut-in because of water production.

INDIVIDUAL RUNS

Four major runs are described in this report and shown diagrammatically on Figure 10. With the exception of Case C, all cases were optimally recompleted in the later project life. It is conceivable that such optimization would provide some additional recovery for Case C. Even with significant improvement, however, the ultimate recovery for this case would still be too low to be an acceptable method of field exploitation.

All cases were normalized to a field abandonment producing rate of 100,000 barrels of oil per day. The variations in operating conditions would probably cause each case to have a different economic limit. Minor variations in the economic limits would not have a significant impact on ultimate recoveries. A much larger impact would result from the energy required to reinject gas that might otherwise be sold. This could exceed 100 million barrels of oil in equivalent BTU content.

The reader should refer to the section entitled Boundary Conditions for other common parameters to the following cases:

Case A - had no gas sales and no source water injection. Total oil recovery was 8.42 billion stock tank barrels representing 40.8% OOIP in 36.3 years.

Case B - had no gas sales with source water injection of 2 million barrels per day or less, governed by reservoir pressure. Total oil recovery was 9.51 billion stock tank barrels representing 46.1% OOIP in 37.5 years.

Case C - had gas sales of 2 billion cubic feet per day and no source water injection. Total oil recovery was 7.42 billion stock tank barrels representing 35.9% OOIP in 24.2 years.

Case D - had gas sales of 2 billion cubic feet per day and source water injection of 2 million barrels per day. Total oil recovery was 9.37 billion stock tank barrels representing 45.4% OOIP in 26.6 years.

The results of these four cases are plotted on Figures 11 through 22.

EFFECTS OF GAS CYCLING AND CONING

Some additional runs were made to evaluate the effect of added gas recycling capacity. Results are not yet conclusive and additional work is recommended.

The effect of gas coning was also evaluated. This was done by increasing the well gas-oil relative permeability ratio. Gas coning

effects in the runs used in this study reduced recovery percentages from 3 to 6. While these are valid numbers, additional runs are necessary using adverse gas-oil relative permeability values and permeability variations to further determine the sensitivity to gas coning.

TABLE I

ORIGINAL HYDROCARBONS IN-PLACE
SADLEROCHIT FORMATION
PRUDHOE BAY FIELD

Zone	Stock Tank Oil Billion Barrels		Solution Gas Trillion Standard Cubic Feet		Gas Cap Gas Trillion Standard Cubic Feet		Gas Cap Condensate Stock Tank Oil Million Barrels	
Study Date	1974	1978	1974	1978	1974	1978	1974	1978
Upper	8.6	9.0	6.3	6.5	10.4	10.3	358	354
Middle	5.0	5.7	3.6	4.1	6.0	7.0	206	241
Lower	5.5	5.9	4.0	4.3	4.8	6.1	165	210
TOTALS	19.1	20.6	13.9	14.9	21.2	23.4	729	805

TABLE II

RECOMPLETION SCHEDULE FOR CASES A, B, C, D
PRUDHOE BAY FIELD

Days	Yrs	Case A	Case B	Case C	Case D
1,855	5	8 wells, *	8 wells, *	8 wells, *	8 wells, *
		8 wells, **	8 wells, **	8 wells, **	8 wells, **
2,220	6	152 wells, **	152 wells, **	152 wells, **	152 wells, **
		1 well, *	1 well, *	1 well, *	1 well, *
2,585	7	189 wells,**	189 wells,**	189 wells,**	189 wells,**
		1 well,*	1 well,*	1 well,*	1 well,*
2,950	[1]8	24 wells,**	10 wells,*	8 wells,*	11 wells,*
		9 wells,*			
3,315	9	392 wells,**	8 wells,*	12 wells,*	13 wells,*
		21 wells,*			
3,680	10	37 wells,**	19 well,*	14 wells,*	20 wells,*
		8 wells,*			
4,045	11	99 wells,**	22 wells,*	14 wells,*	38 wells,*
		11 wells,*			
4,410	12	20 wells,*	19 wells,*	19 wells,*	24 wells,*
4,775	13	11 wells,*	21 wells,*	5 wells,*	23 wells,*
5,140	14	9 wells,*	13 wells,*	20 wells,*	17 wells,*
5,505	15	5 wells,*	10 wells,*	6 wells,*	13 wells,*
		102 wells,**	102 wells,**	102 wells,**	331 wells,**
5,870	16	9 wells,*	4 wells,*	11 wells,*	2 wells,*
6,235	17	5 wells,*	11 wells,*	11 wells,*	12 wells,*
6,600	18	6 wells,*	7 wells,*	9 wells,*	12 wells,*
6,965	19	2 wells,*	5 wells,*	10 wells,*	5 wells,*
7,330	20	9 wells,*	9 wells,*	13 wells,*	8 wells,*
7,695	21	5 wells,*	6 wells,*	14 wells,*	11 wells,*
8,060	22	6 wells,*	6 wells,*	3 wells,*	17 wells,*
8,425	23	3 wells,*	11 wells,*	11 wells,*	15 wells,*
8,790	24	5 wells,*	2 wells,*		26 wells,*
9,155	25	1 well,*	5 wells,*		27 wells,*
9,520	26				34 wells,*
9,885	27		3 wells,*		38 wells,*
10,250	28	2 wells,*	13 wells,*		
10,615	29		3 wells,*		
10,980	30		2 wells,*		
11,345	31	1 well,*	5 wells,*		
11,710	32	2 wells,*	5 wells,*		
12,075	33	2 wells,*	3 wells,*		
12,440	34	1 well,*	3 wells,*		
12,805	35	1 well,*			

* Model automatically shuts in individual layers due to excessive GOR
** Recompletion of individual layers based on moveable oil

[1] Year 8 is the break for the specific cases of A-D. Some recompletions were made prior to that time.

AGO 533143

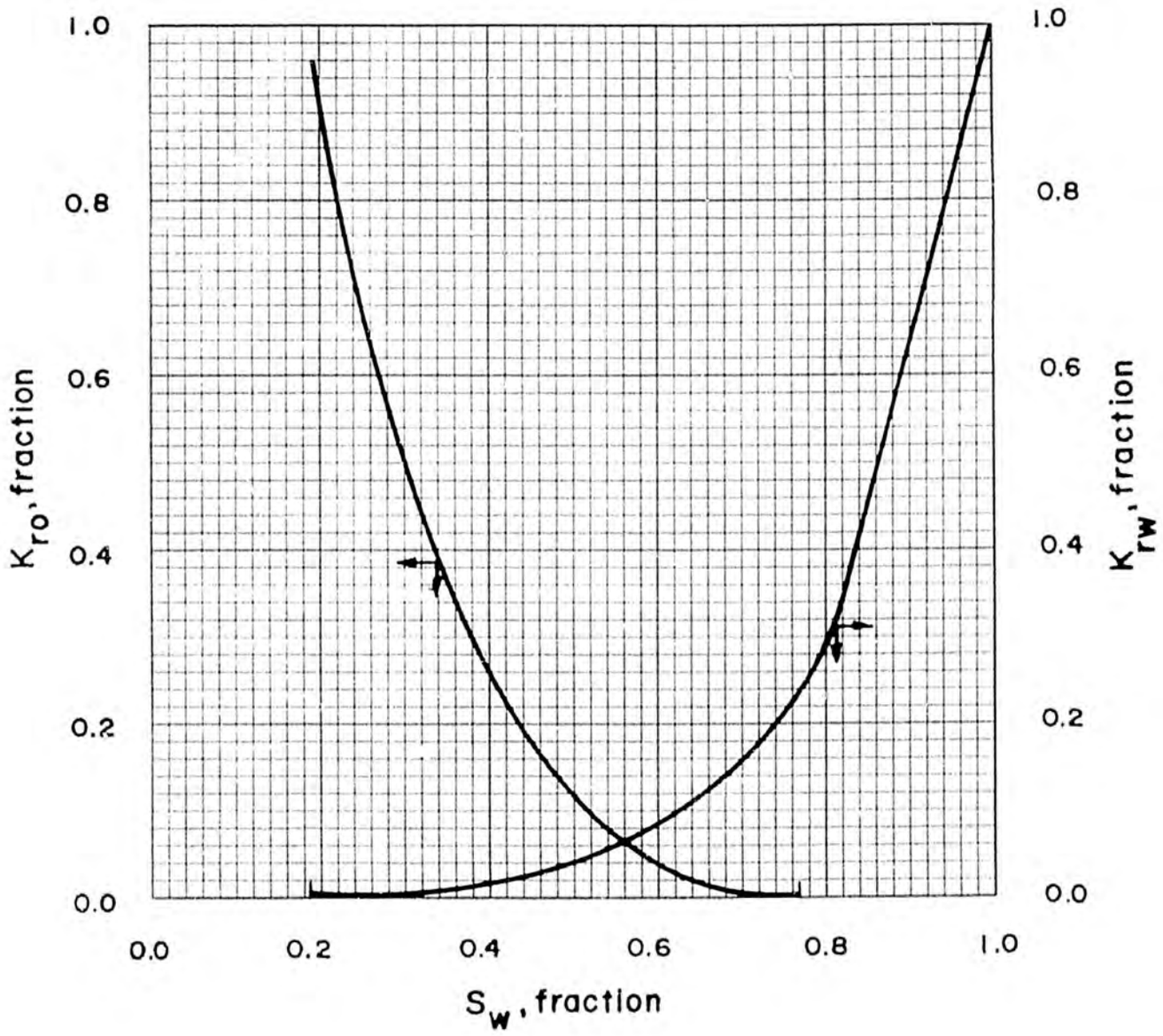
FIGURE 1

A.O.G.C.C.

Prudhoe Bay Field

Two Phase Relative Permeability

K_{ro} and K_{rw} vs S_w



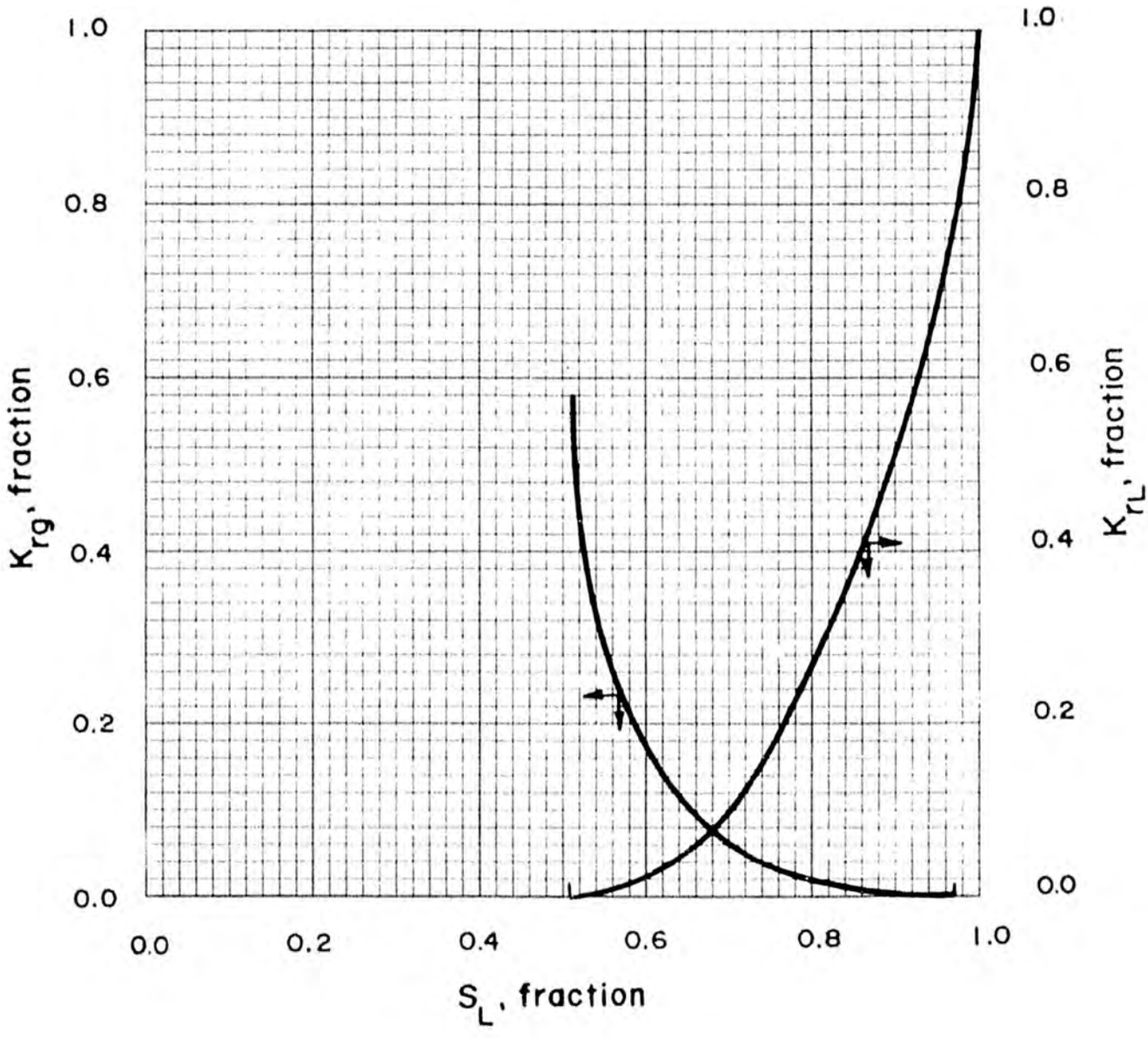
AGO 533144

FIGURE 2

A.O.G.C.C.

Prudhoe Bay Field

Two Phase Relative Permeability
K_{rg} and K_{rL} vs S_L



AGO 533145

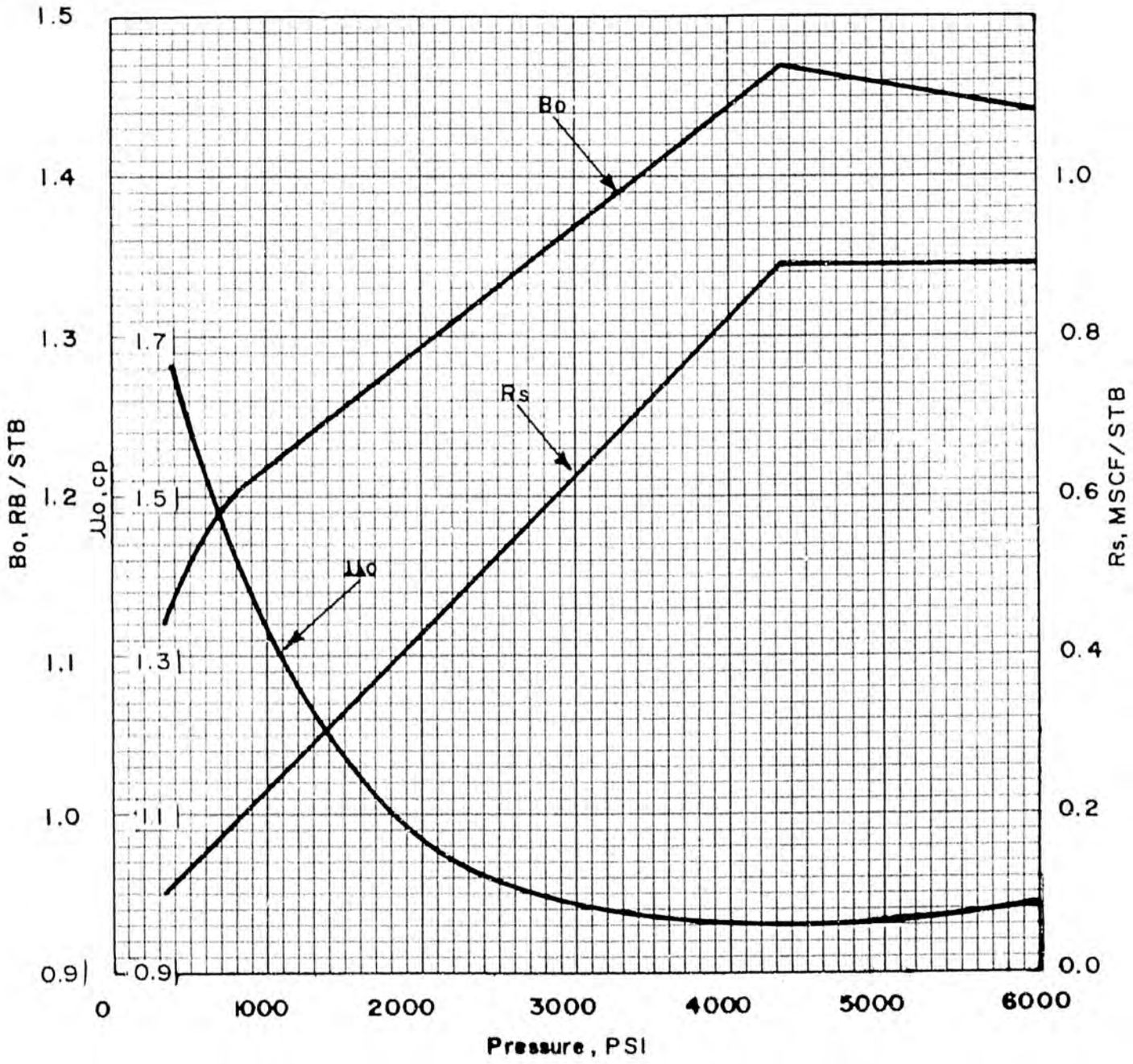
FIGURE 3

A.O.G.C.C.

Prudhoe Bay Field

Oil PVT Table # 1

Oil Properties vs Pressure



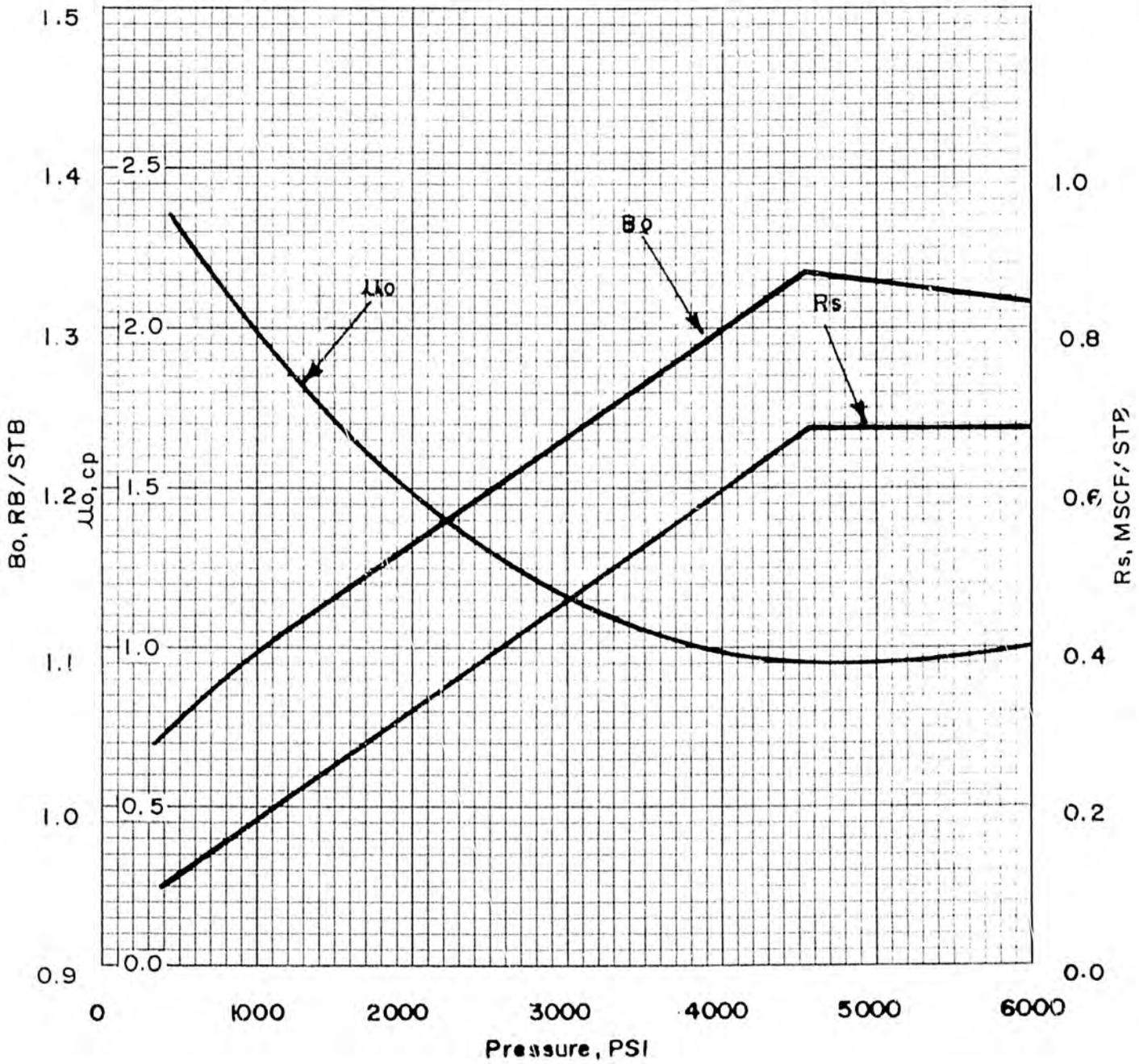
AGO 533146

FIGURE 4

A.O.G.C.C.

Prudhoe Bay Field

Oil PVT Table #2
Oil Properties vs Pressure



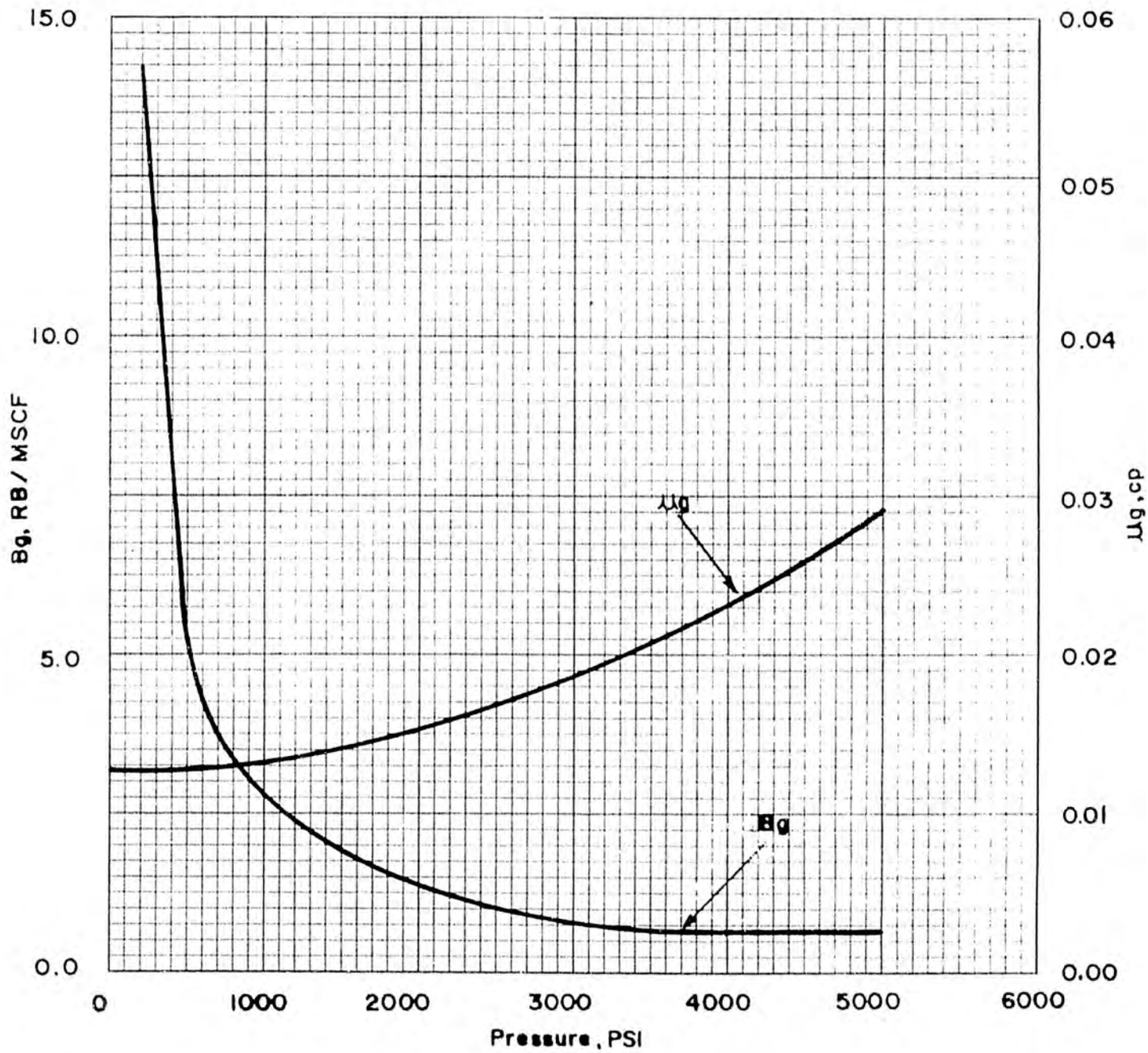
AGO 533147

FIGURE 5

A.O.G.C.C.

Prudhoe Bay Field

Gas PVT Table # 1
Gas Properties vs Pressure



AGO 533148

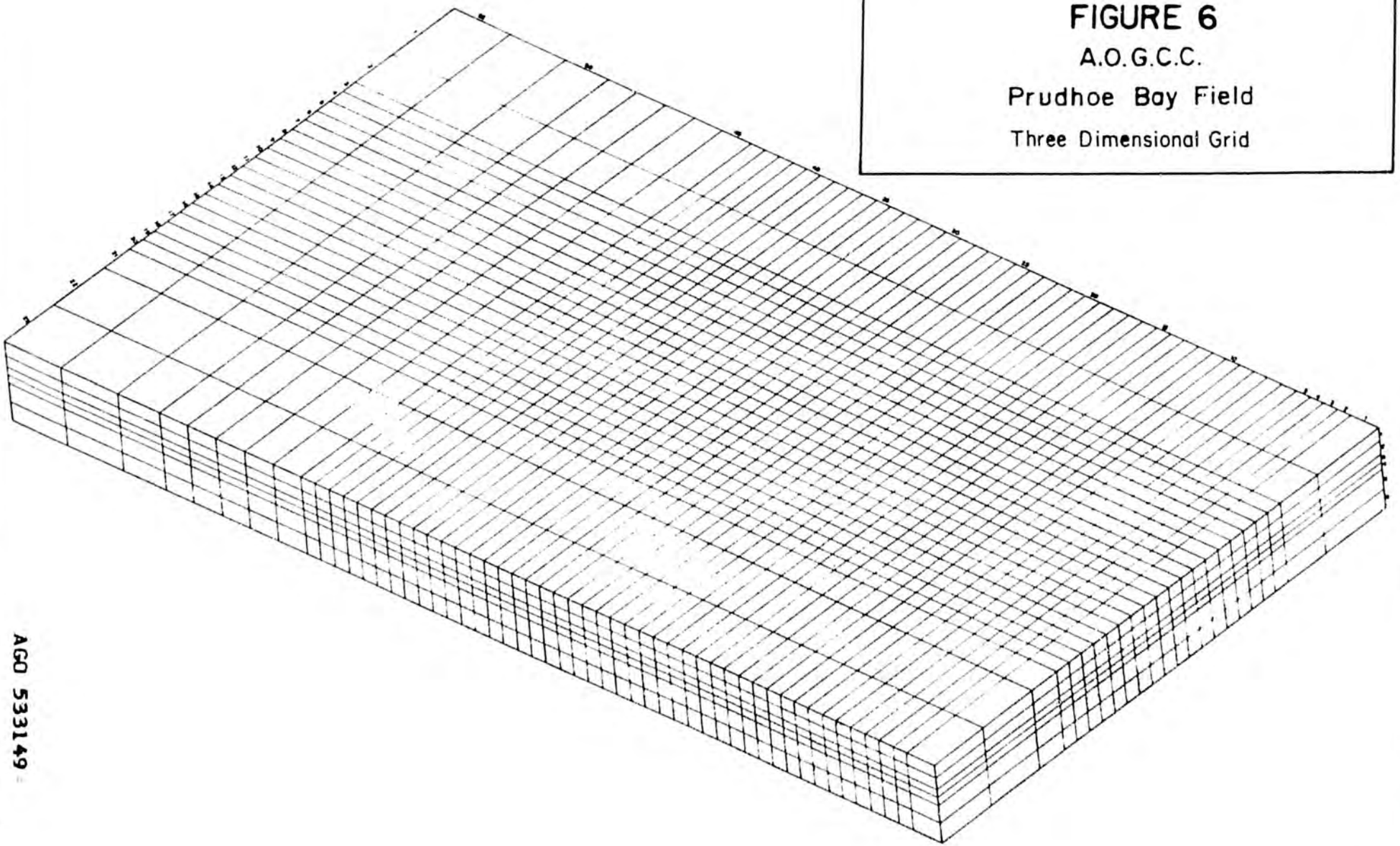


FIGURE 6

A.O.G.C.C.

Prudhoe Bay Field

Three Dimensional Grid

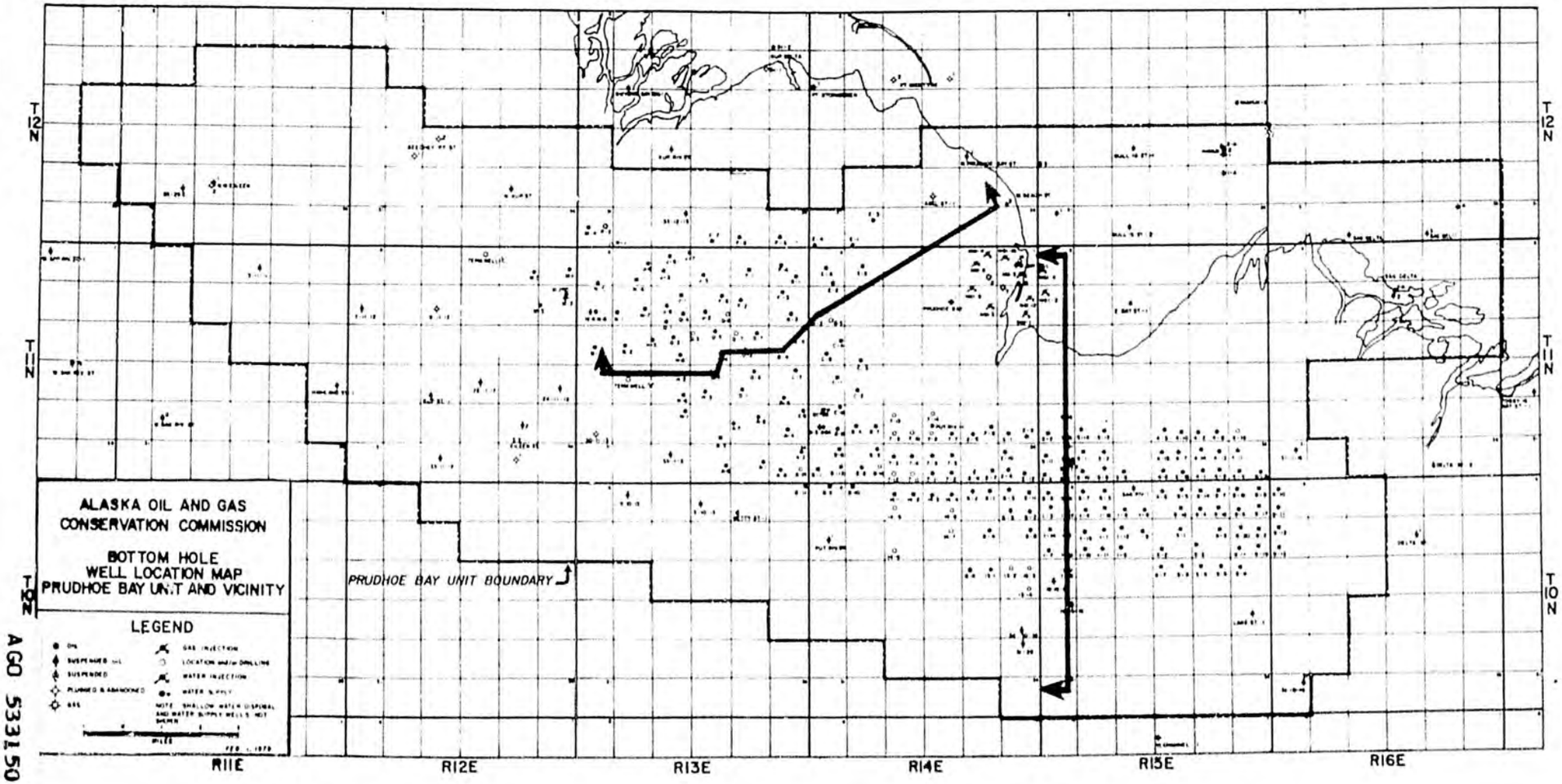
AGO 533149

FIGURE 7

A.O.G.C.C.

Prudhoe Bay Field

Cross-Section Model Locations



AGO 533150

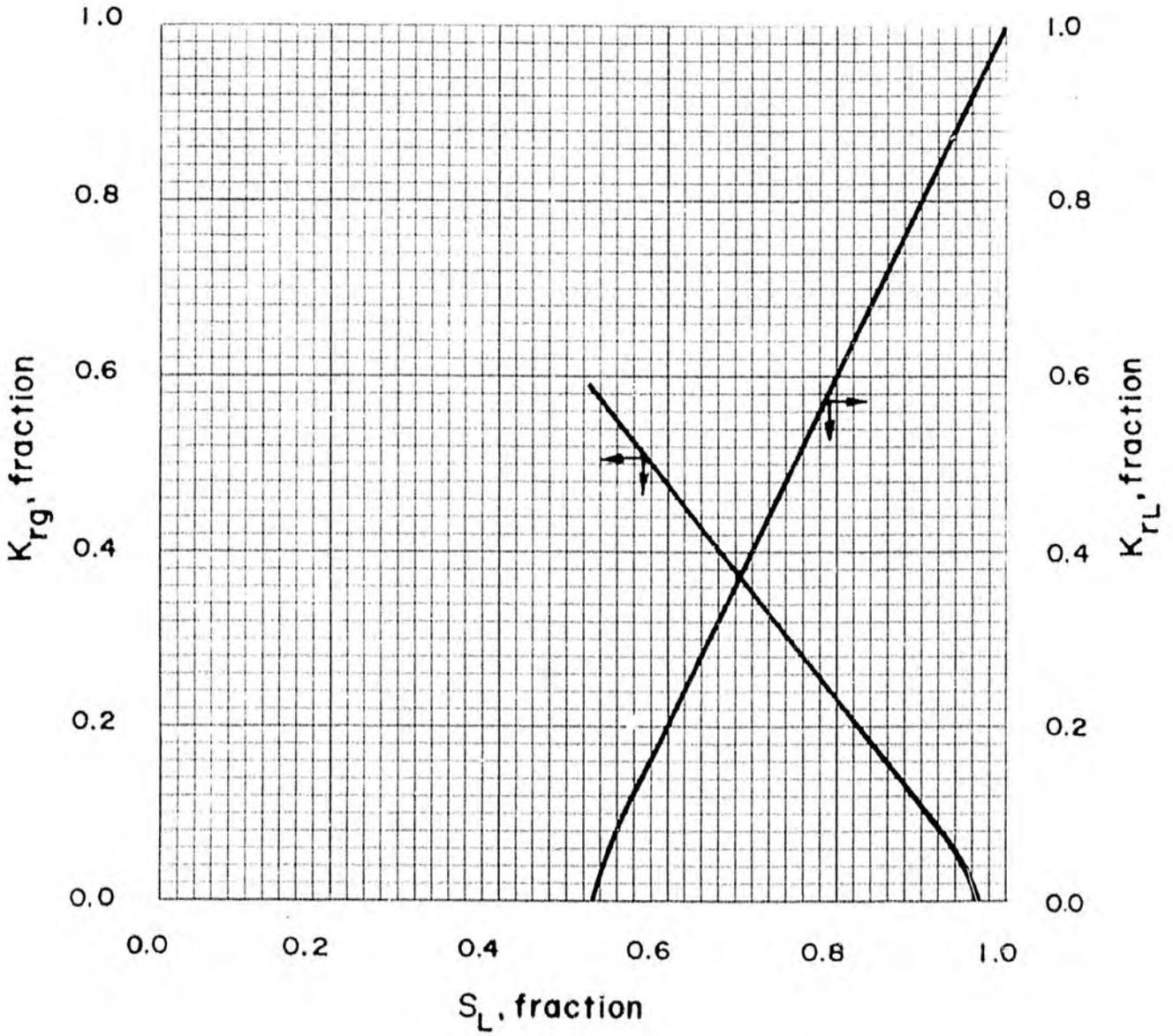
FIGURE 8

A.O.G.C.C.

Prudhoe Bay Field

Cell to Cell Relative Permeability

K_{rg} and K_{rL} vs S_L



AGO 533151

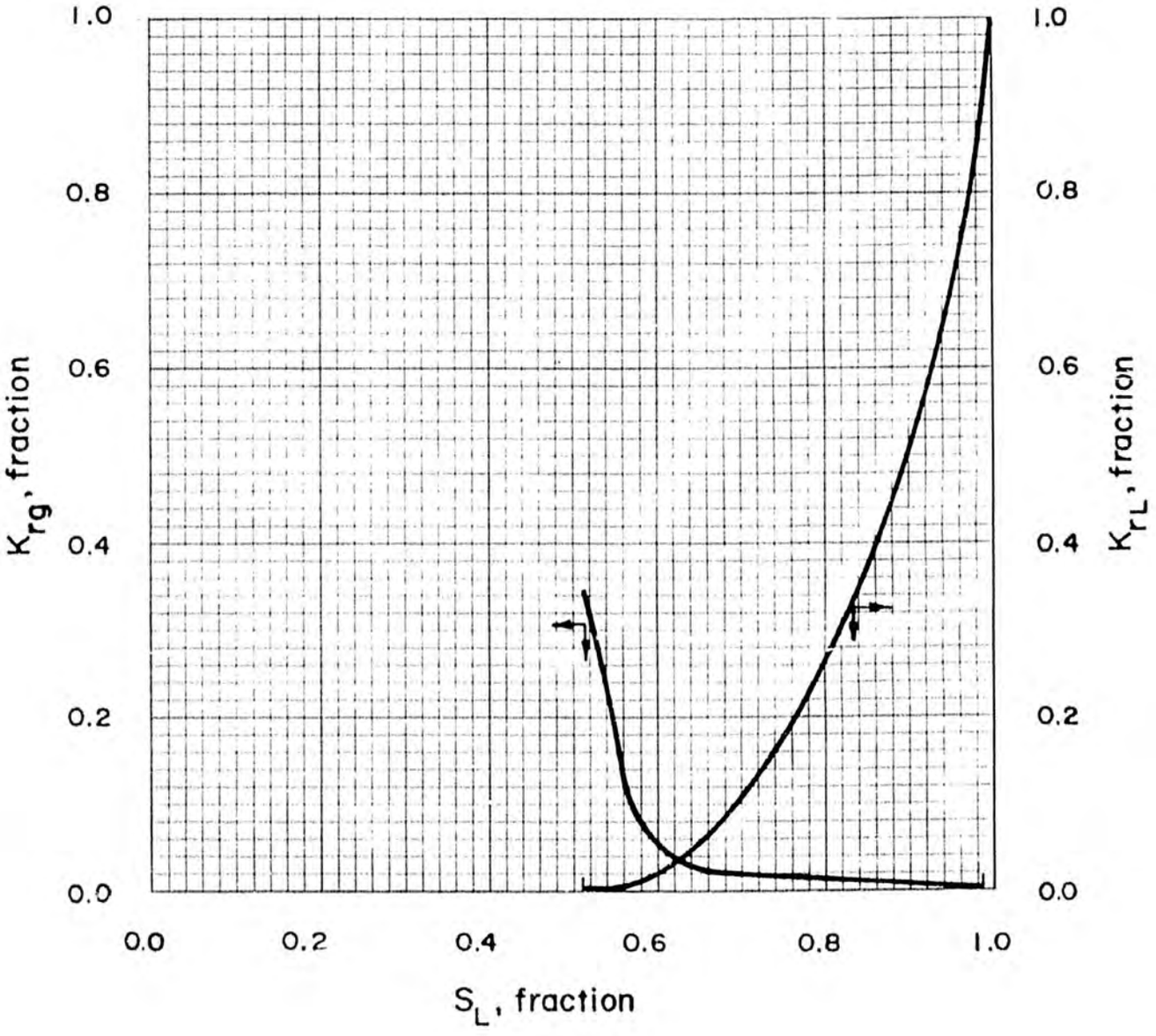
FIGURE 9

A.O.G.C.C.

Prudhoe Bay Field

Individual Well Relative Permeability

K_{rg} and K_{rL} vs S_L



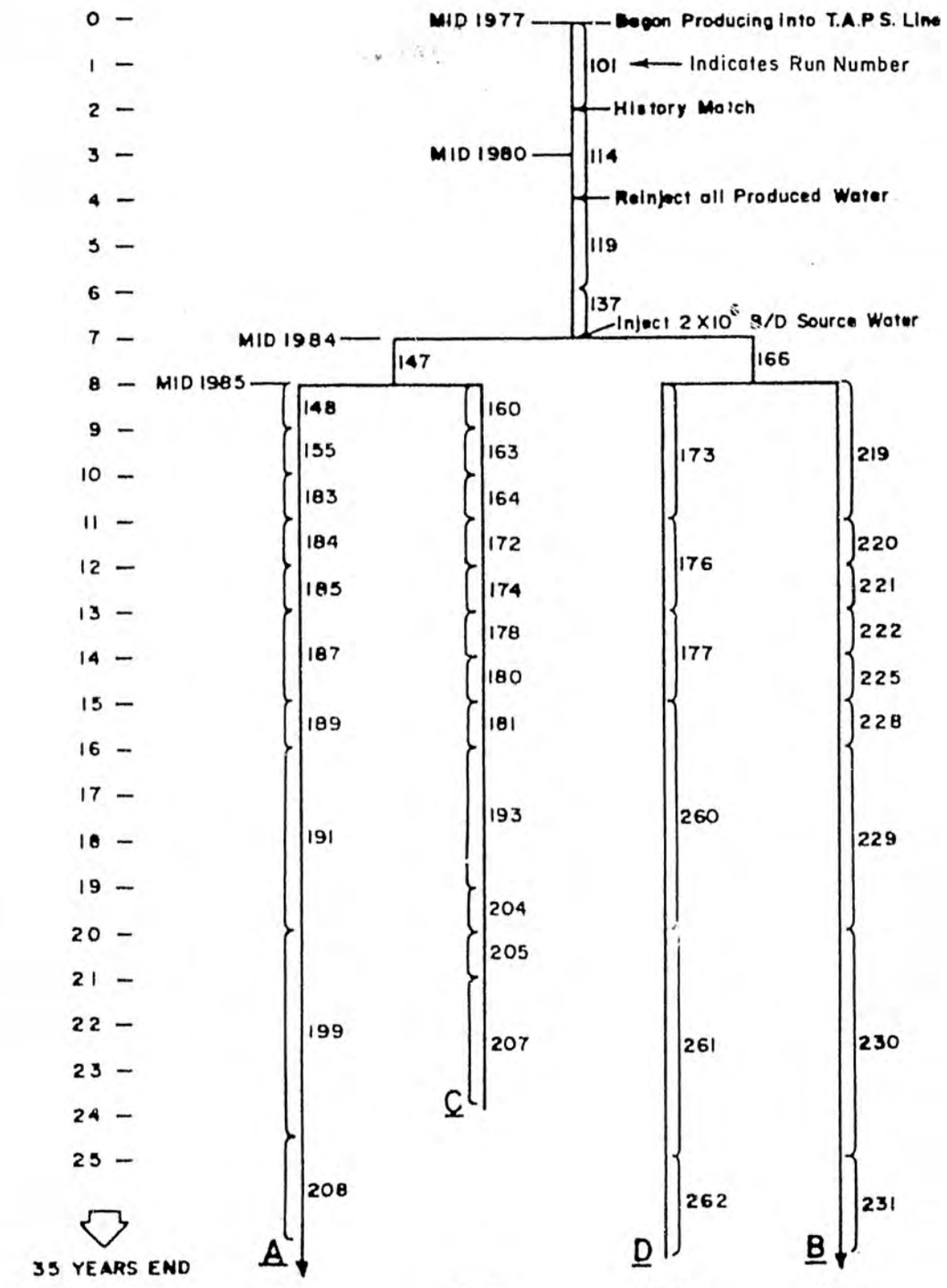
AGO 533152

FIGURE 10

A.O.G.C.C.

Prudhoe Bay Field

Schematic Representation of Cases A, B, C and D



AGO 533\53

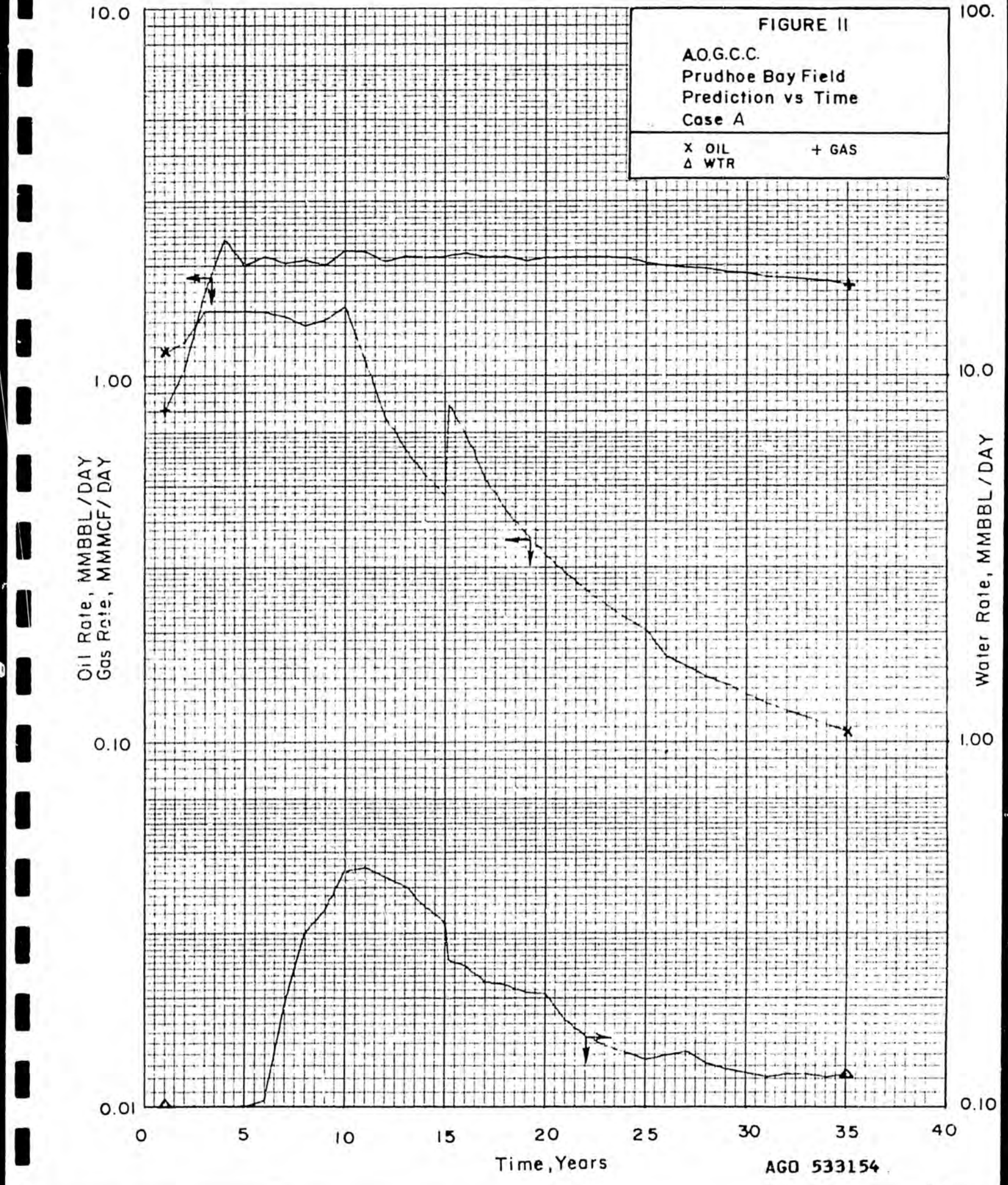


FIGURE II
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Time
Case A
X OIL
Δ WTR
+ GAS
10.0
1.00
0.10
0.01
100.
10.0
1.00
0.10
Oil Rate, MMBBL/DAY
Gas Rate, MMMCF/DAY
Water Rate, MMBBL/DAY
0
5
10
15
20
25
30
35
40
Time, Years
AGO 533154

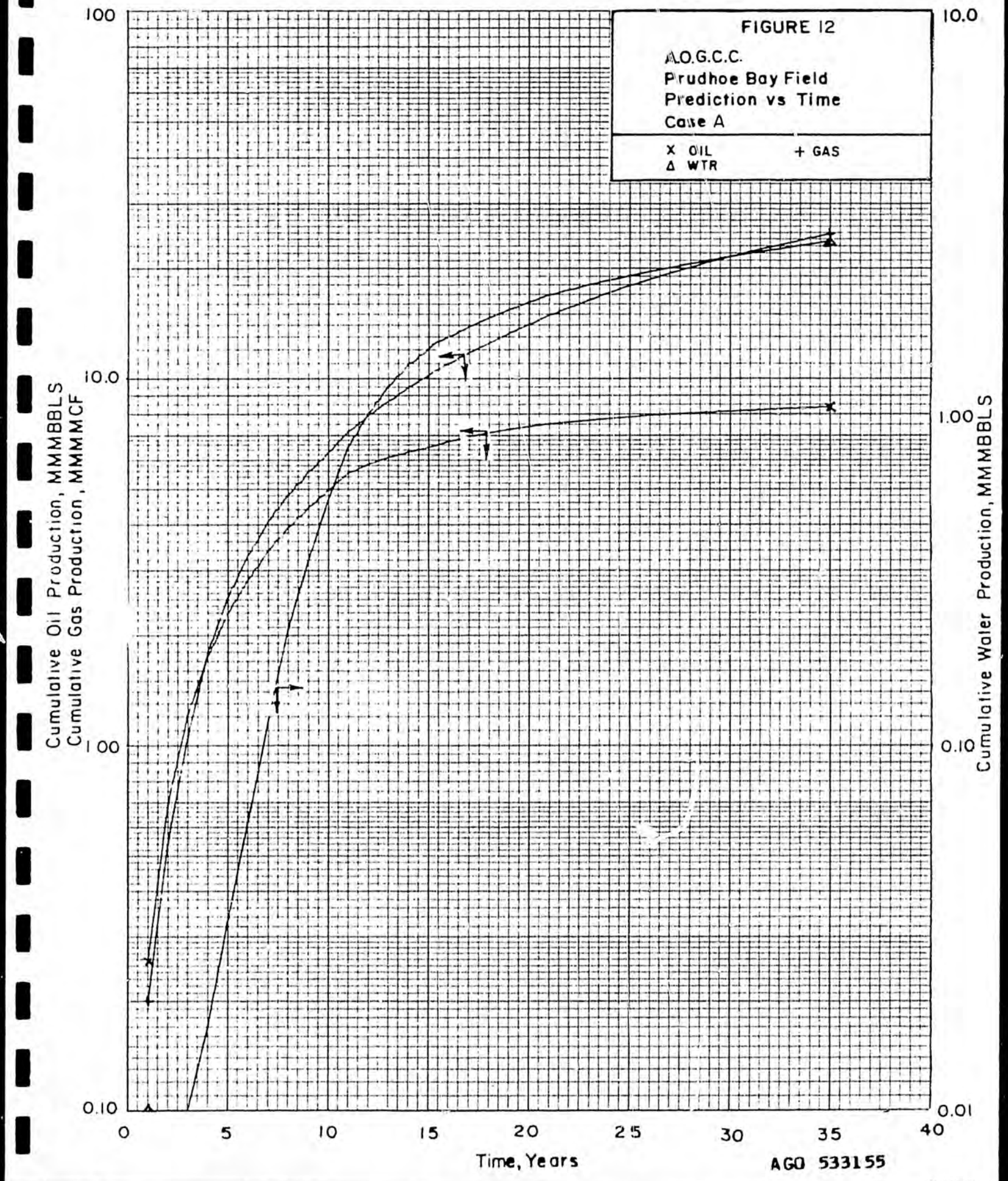


FIGURE 12
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Time
Case A
X OIL
Δ WTR
+ GAS
100
10.0
1.00
0.10
10.0
1.00
0.10
0.01
0
5
10
15
20
25
30
35
40
Cumulative Oil Production, MMMBBLS
Cumulative Gas Production, MMMMCF
Cumulative Water Production, MMMBBLS
Time, Years
AGO 533155

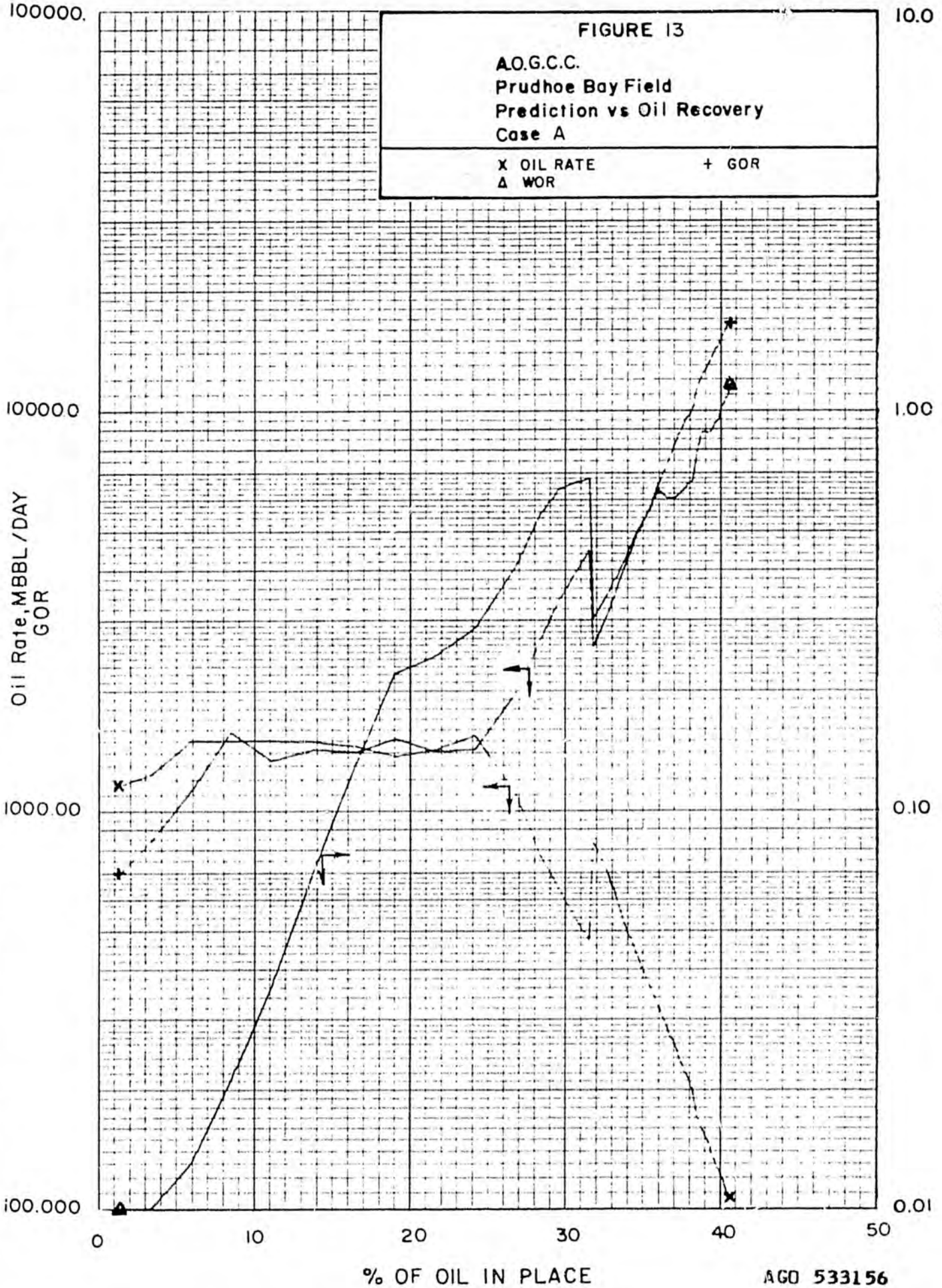


FIGURE 13
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Oil Recovery
Case A
X OIL RATE
+ GOR
Δ WOR
100000.
10000.0
1000.00
100.000
Oil Rate, MBBL/DAY
GOR
10.0
1.00
0.10
0.01
WOR
0
10
20
30
40
50
% OF OIL IN PLACE
AGO 533156

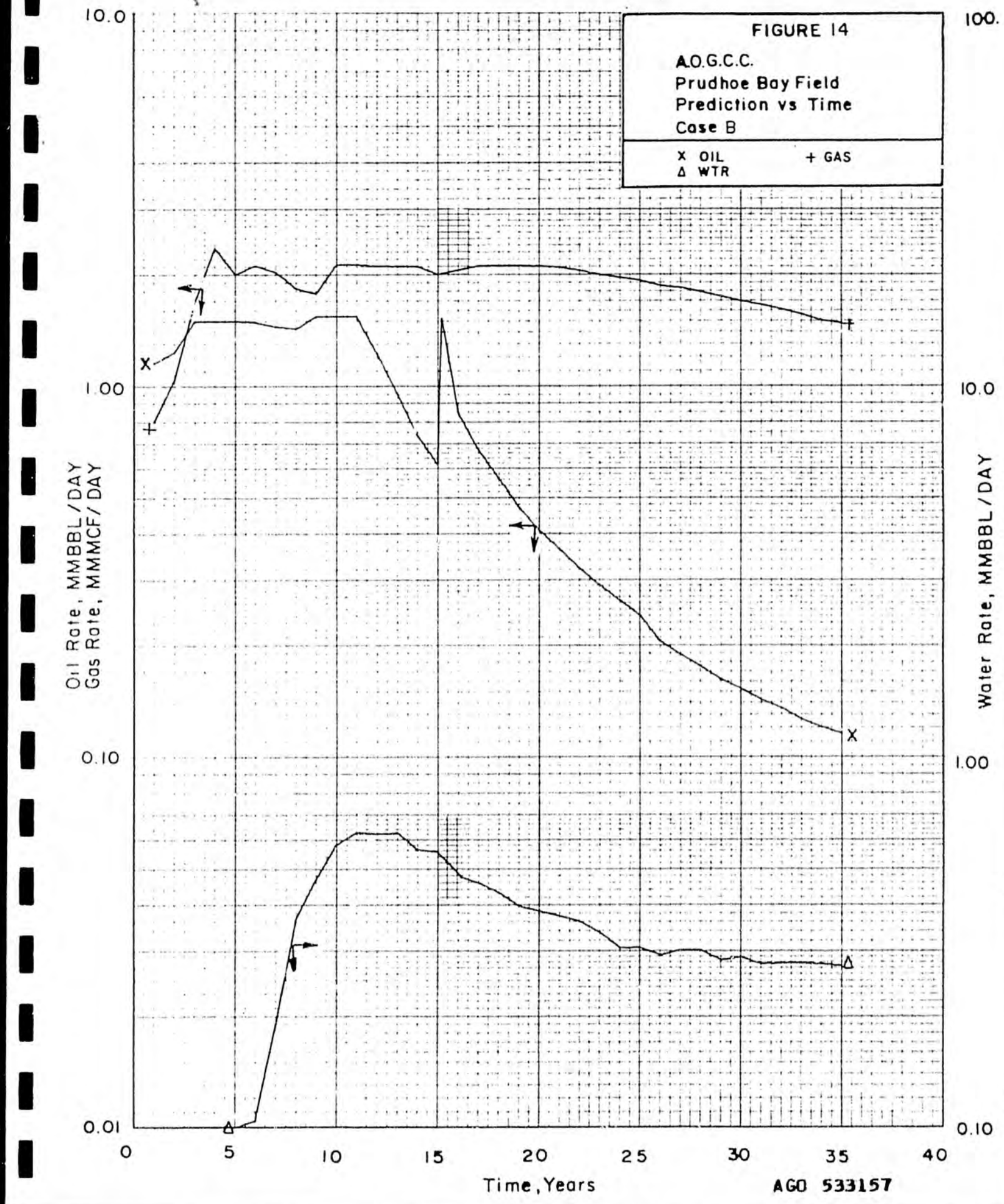


FIGURE 14
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Time
Case B
X OIL
+ GAS
Δ WTR
10.0
1.00
0.10
0.01
100.
10.0
1.00
0.10
0
5
10
15
20
25
30
35
40
Oil Rate, MMBBL/DAY
Gas Rate, MMMCF/DAY
Water Rate, MMBBL/DAY
Time, Years
AGO 533157

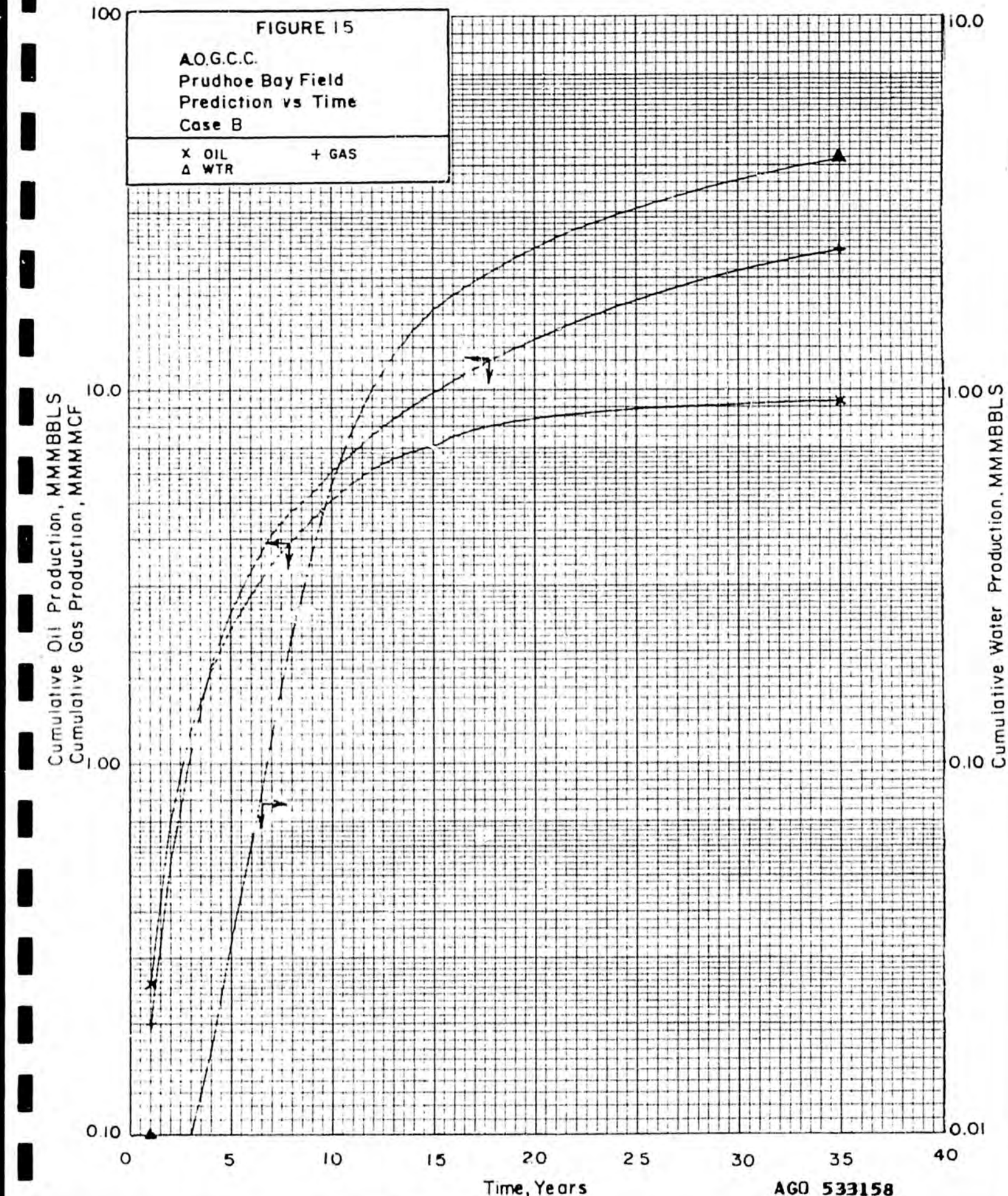


FIGURE 15
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Time
Case B
X OIL
Δ WTR
+ GAS
100
10.0
1.00
0.10
10.0
1.00
0.10
0.01
Cumulative Oil Production, MMMBBLS
Cumulative Gas Production, MMMMCF
Cumulative Water Production, MMMBBLS
0
5
10
15
20
25
30
35
40
Time, Years
AGO 533158

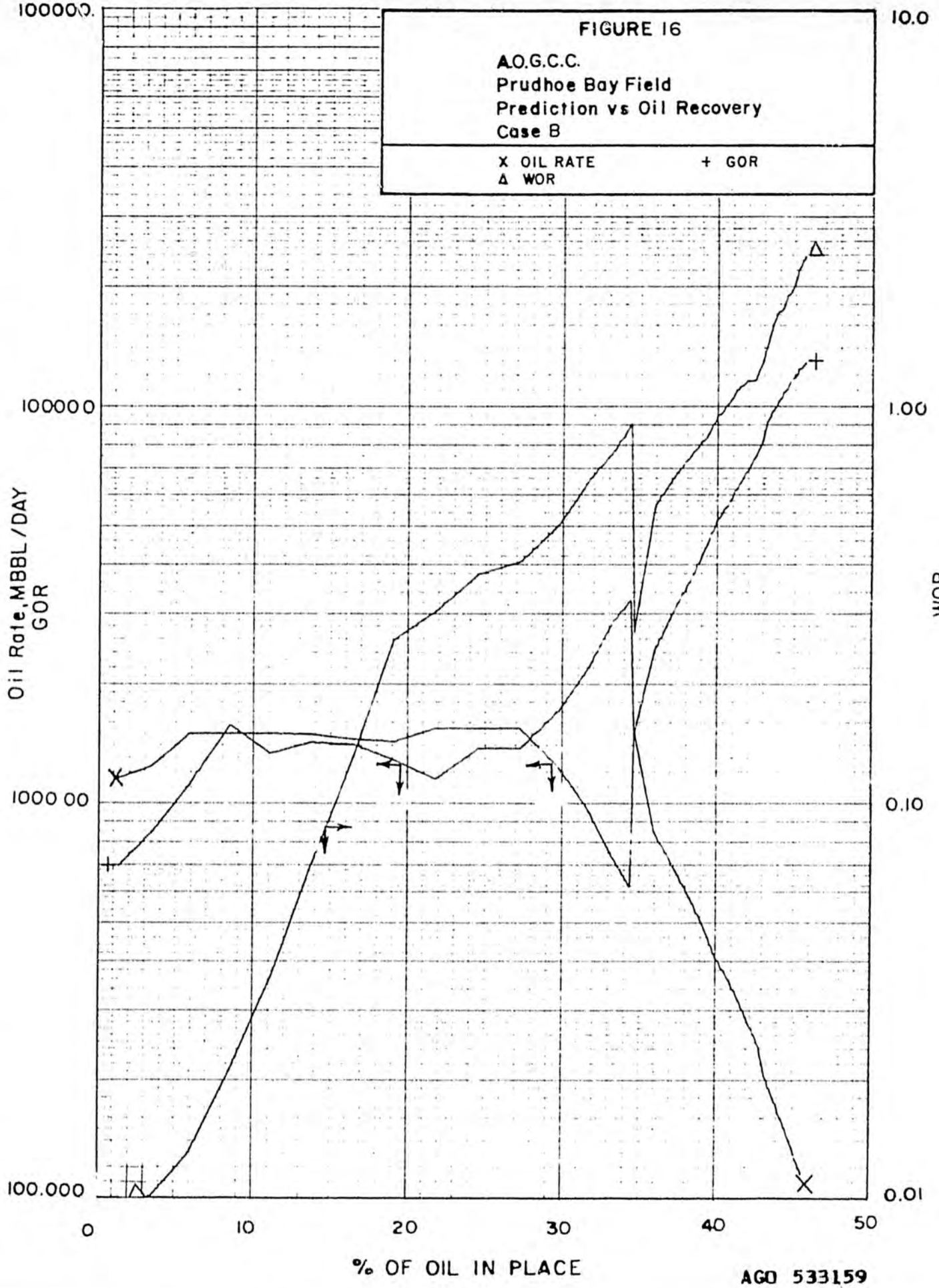


FIGURE 16
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Oil Recovery
Case B
X OIL RATE
+ GOR
Δ WOR
100000.
10000 0
1000 00
100.000
10.0
1.00
0.10
0.01
Oil Rate, MBBL/DAY
GOR
WOR
0
10
20
30
40
50
% OF OIL IN PLACE
AGO 533159

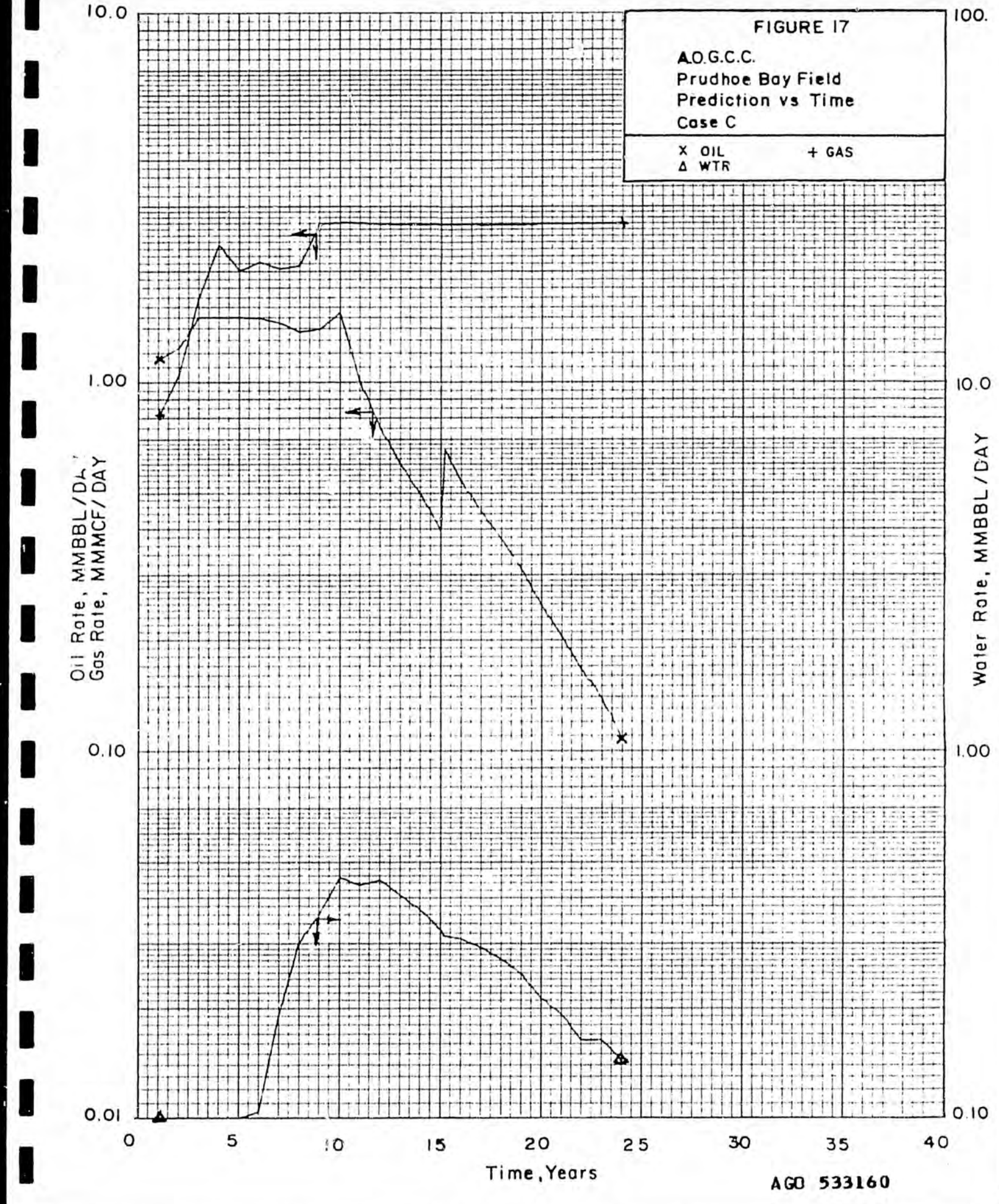


FIGURE 17
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Time
Case C
X OIL
Δ WTR
+ GAS
10.0
1.00
0.10
0.01
100.
10.0
1.00
0.10
Oil Rate, MMBBL/DAY
Gas Rate, MMMCF/DAY
Water Rate, MMBBL/DAY
0
5
10
15
20
25
30
35
40
Time, Years
AGO 533160

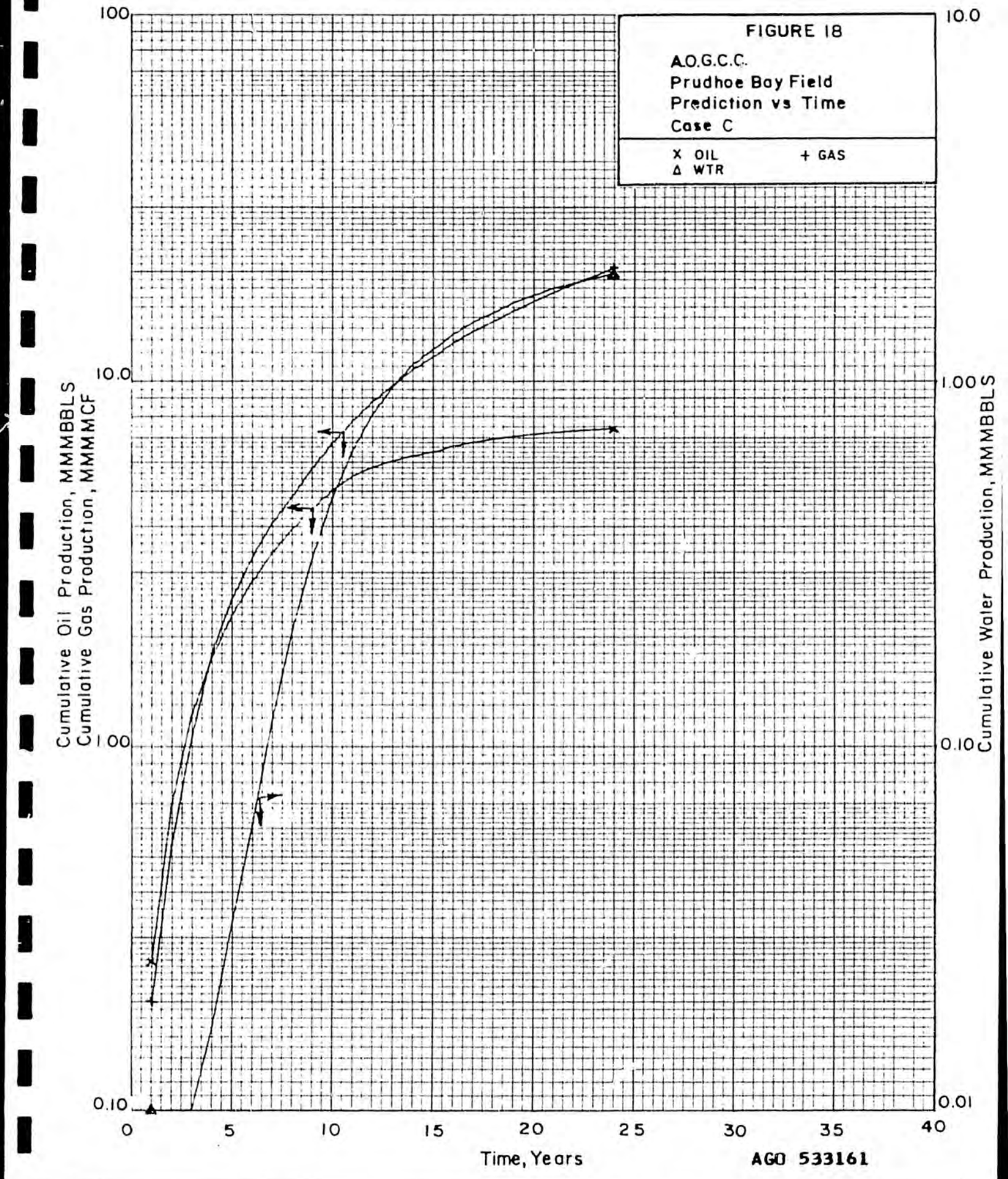


FIGURE 18
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Time
Case C
X OIL
Δ WTR
+ GAS
100
10.0
1.00
0.10
10.0
1.00
0.10
0.01
Cumulative Oil Production, MMMBBLS
Cumulative Gas Production, MMMMCF
Cumulative Water Production, MMMBBLS
0
5
10
15
20
25
30
35
40
Time, Years
AGO 533161

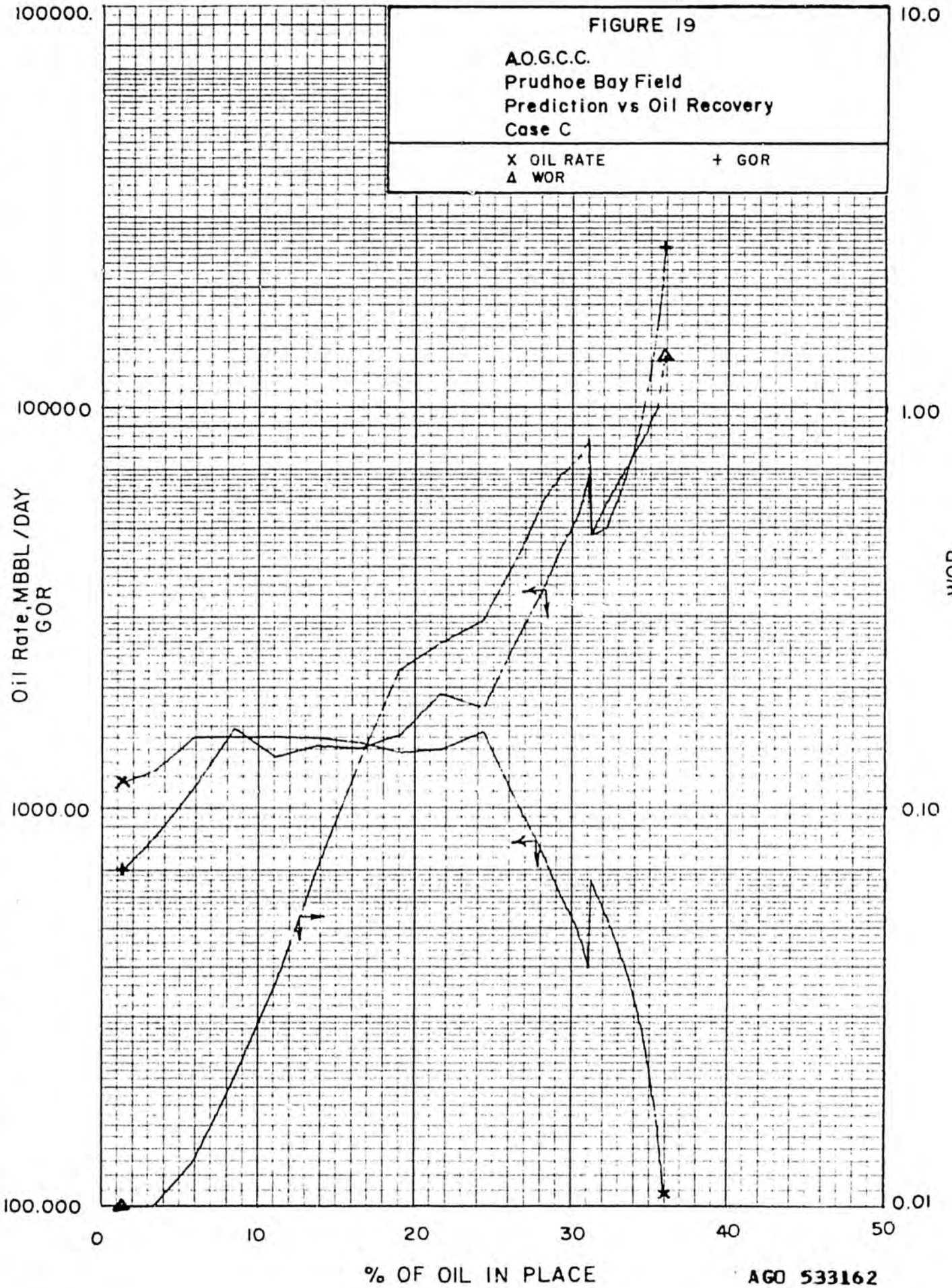
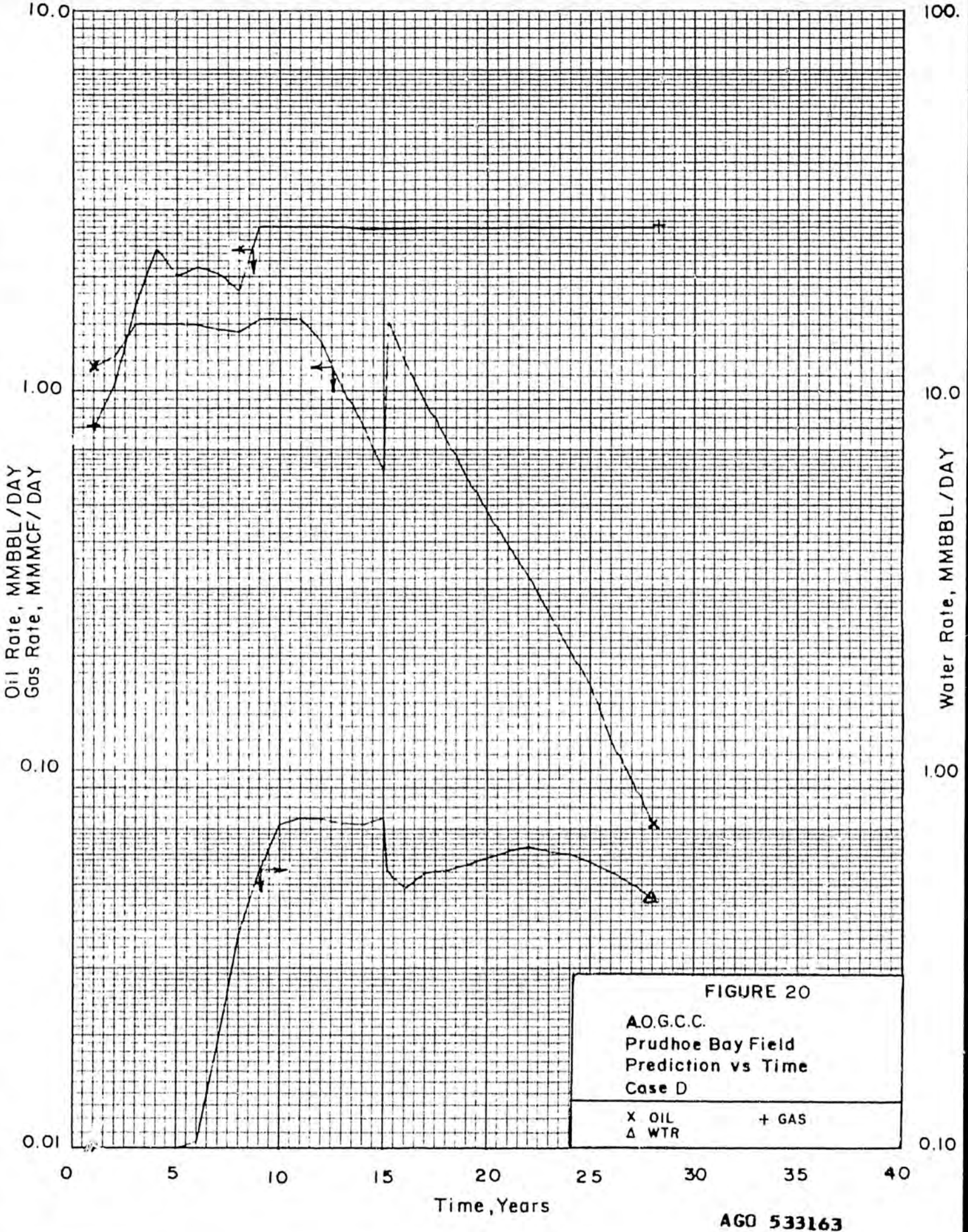


FIGURE 19
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Oil Recovery
Case C
X OIL RATE
+ GOR
Δ WOR
100000.
100000
1000.00
100.000
10.0
1.00
0.10
0.01
Oil Rate, MBBL/DAY
GOR
WOR
0
10
20
30
40
50
% OF OIL IN PLACE
AGO 533162


10.0
1.00
0.10
0.01
100.
10.0
1.00
0.10
Oil Rate, MMBBL/DAY
Gas Rate, MMMCF/DAY
Water Rate, MMBBL/DAY
0
5
10
15
20
25
30
35
40
Time, Years
FIGURE 20
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Time
Case D
X OIL
+ GAS
Δ WTR
AGO 533163

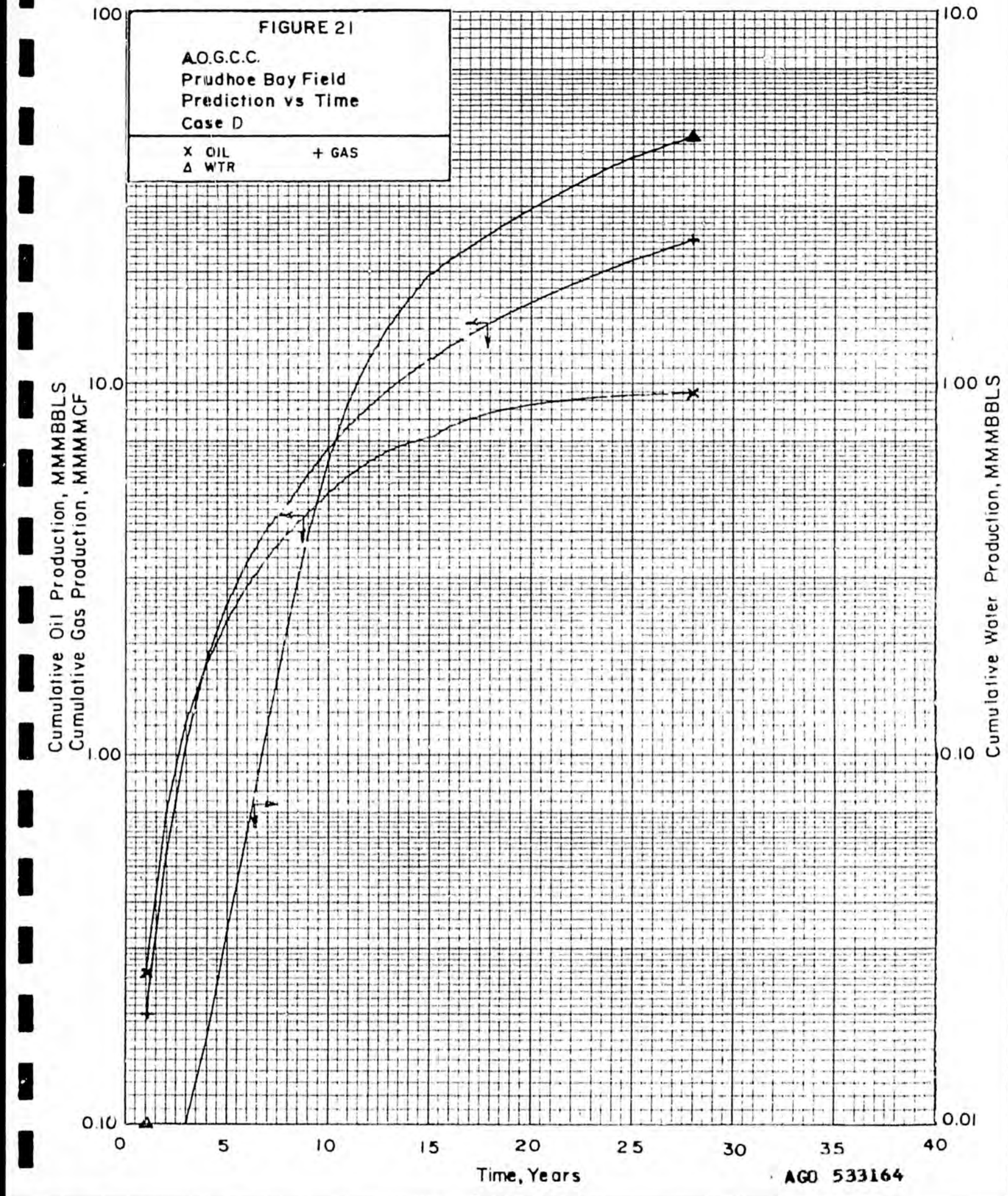


FIGURE 21
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Time
Case D
X OIL
Δ WTR
+ GAS
100
10.0
1.00
0.10
10.0
1.00
0.10
0.01
0
5
10
15
20
25
30
35
40
Time, Years
Cumulative Oil Production, MMMBBLS
Cumulative Gas Production, MMMMCF
Cumulative Water Production, MMMBBLS
AGO 533164

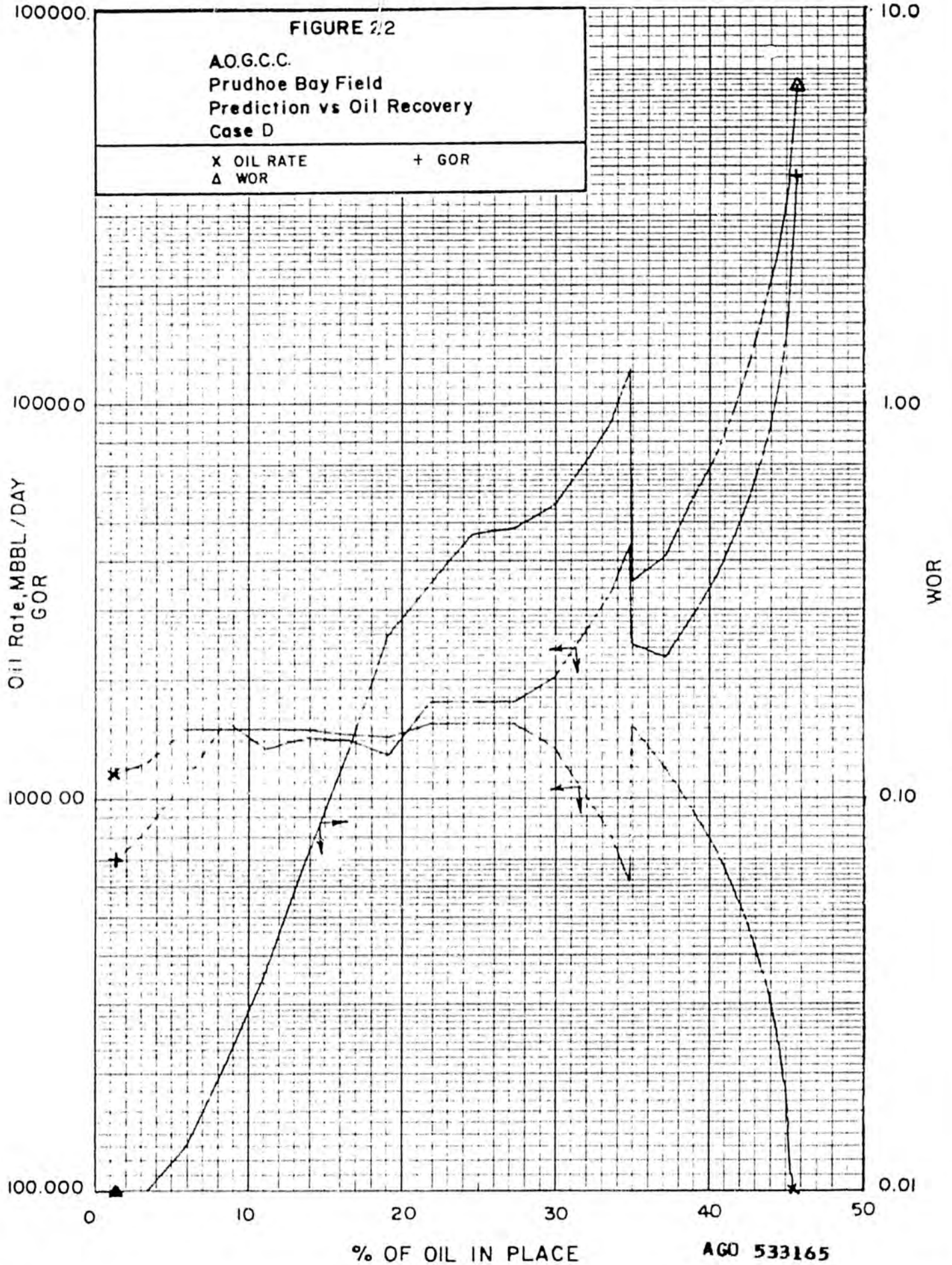
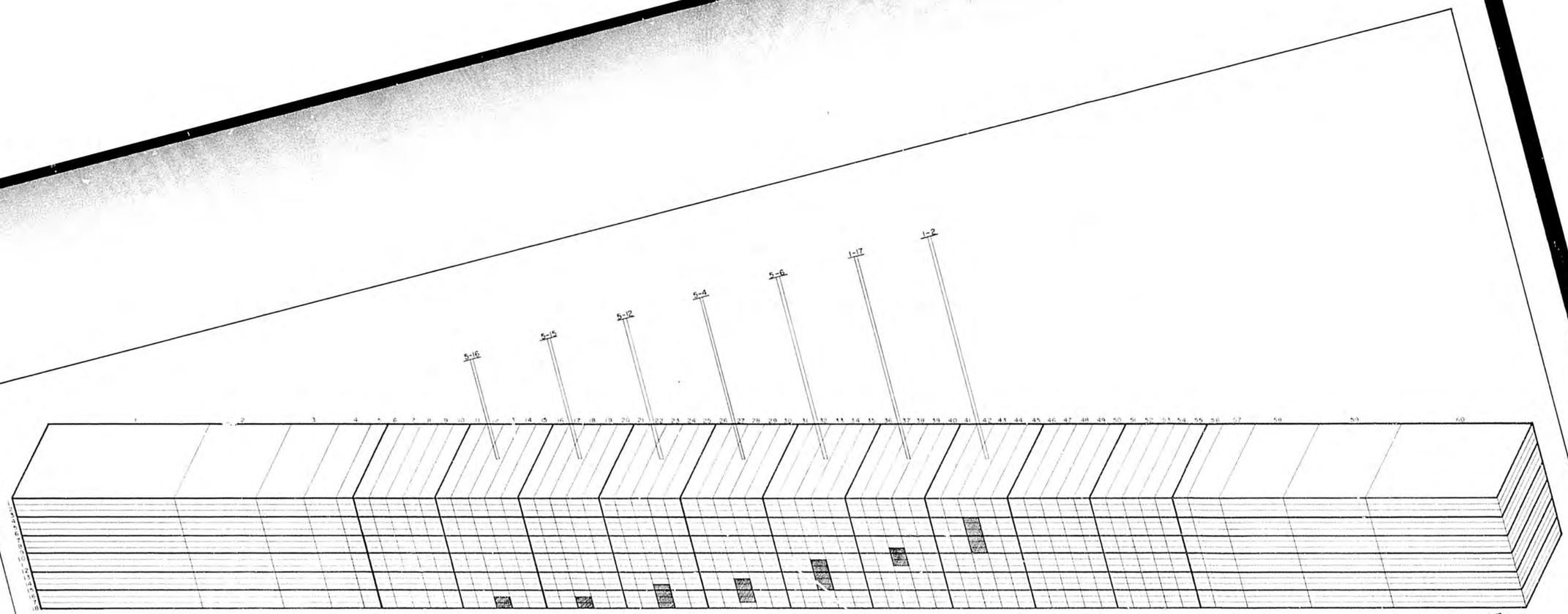


FIGURE 2.2
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Oil Recovery
Case D
X OIL RATE
+ GOR
Δ WOR
100000.
100000
1000 00
100.000
10.0
1.00
0.10
0.01
Oil Rate, MBBL/DAY
GOR
WOR
0
10
20
30
40
50
% OF OIL IN PLACE
AGO 533165



LEGEND

Well

Perforated Zone

EXHIBIT A

H.K. VAN POOLLEN AND ASSOCIATES, INC.

A.O.G.C.C

PRUDHOE BAY FIELD

North-South Cross Section

AGO 533166

A60533166

LEGEND

Well

Perforated Zone

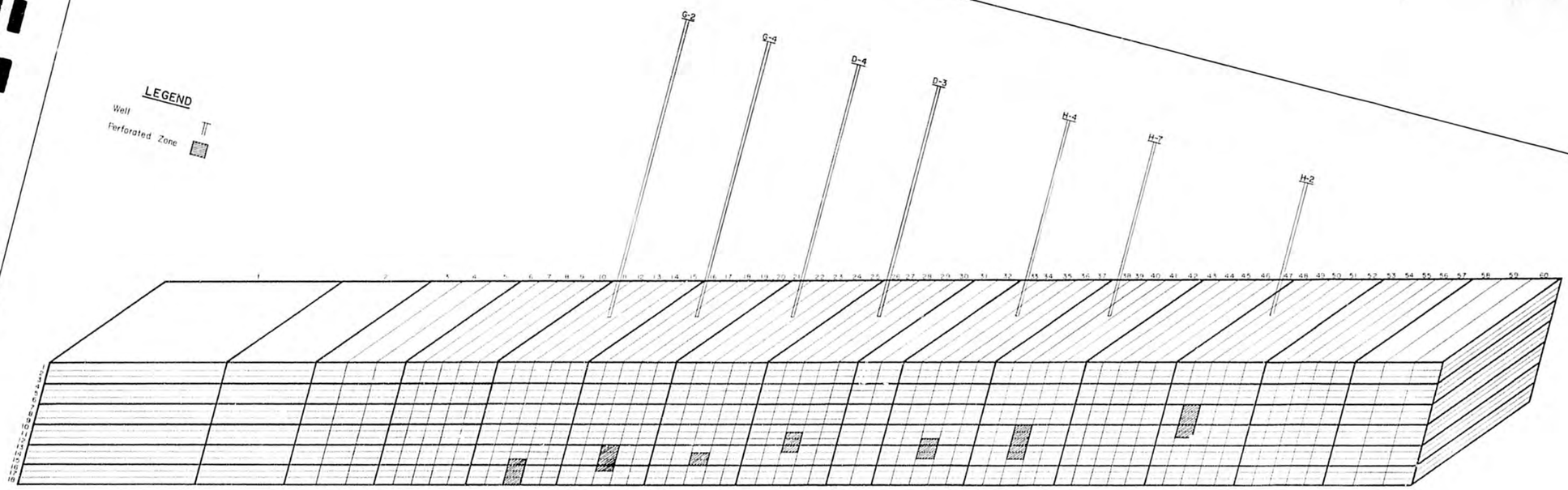


EXHIBIT B
H.K. VAN POOLLEN AND ASSOCIATES, INC.
A.O.G.C.C.
PRUDHOE BAY FIELD
East-West Cross Section

AGO 533167

AGO 533167

Oil & Gas new

Alaska State Legislature

Senate

JUNEAU, ALASKA

5/10/77

TO: Senator Rader
FR: Connie Barlow, Assistant
RE: Materials distributed at May 5 Royalty Board meeting

cc: Poland, Croft, Huber, Colletta
Malone, Osterback, Gruening

Don Wold, executive director of the Royalty Board supplied our office with materials relating to the Royalty Board meeting that took place on May 5, 6. I asked for a few extra copies to pass on to interested legislators. These are attached:

(1) Final Policies for Disposition of Royalty Oil & Gas

The Board adopted a set of 8 policies following testimony on 10 draft policies by Hammond, Rader, Osterback, and Silides.

(2) Statement of Governor Hammond on Royalty Oil Disposition

(Note: Osterback and Silides supplied written statements too.)

(3) "Criteria Document" (lead agency in preparation was DPDP)

Board hopes to use this document for determining the "net benefit" of the various refinery proposals; and in order to specify how the existing proposals need to be more detailed. (Phase I questions are to be incorporated in the final solicitation notice of May 15) Don Wold is looking for comments on this document by Board members, purchasers, and legislators.

SCHEDULE

The Board informally adopted a schedule for completing a large-volume refinery sale:

- May 15 - final solicitation of proposals (specific questions pulled out of "Criteria Document")
- Aug 1 - preliminary proposals due
- Nov 1 - final proposals due
- Dec 1 - final selection of proposal, negotiation begin
- Feb 1 - contract submitted for legislative approval.

AGO 533168

POLICY STATEMENT MADE BY

The Alaska Royalty Oil and Gas
Development Advisory Board

May 5 & 6, 1977

1. The Royalty Oil and Gas Board shall recommend disposition of royalty oil and gas (through in-value taking, in-kind taking, sales, and sales conditions) in such a manner to maximize net benefits to the State. These net benefits include not only price, but also the various economic, social, and environmental ramifications, including employment, local training, Alaskan ownership, secondary effects, tax base, and many other factors.

2. The baseline price for any royalty oil or gas sale shall not be less than the price that would be received for that oil or gas if taken "in-value".

3. Preference will be given first to existing in-state facilities with no alternate sources of oil or gas, and second to those who will construct new in-state facilities or expand existing in-state facilities.

4. A portion of royalty oil will be withheld, meet from long-term committment in order to anticipated future small local demands.

5. With the exception of small sales to public utilities, sales will be for specified volumes or proportions of production, constant throughout the year, rather than for flexible volume "options" to be called by the purchaser.

6. Sales of royalty oil and gas for in-state processing will attempt to insure that products for in-state use are priced at the lowest possible price, within the limits of the general net benefit policy and the pricing policy.

7. Products produced from royalty oil and exported from the State must be surplus to the State's domestic and industrial product needs.

8. In general royalty oil and gas will be disposed of in long-term contracts, rather than in "piece lots" as may be done by a private-sector trader or dealer.

PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

COMMENTS BY GOVERNOR JAY S. HAMMOND
ALASKA ROYALTY OIL AND GAS BOARD
MAY 5, 1977

MR. CHAIRMAN AND MEMBERS OF THE BOARD, I AM DELIGHTED TO TAKE THIS OPPORTUNITY TO DISCUSS PRESENT AND FUTURE POLICIES REGARDING DISPOSITION OF OUR ROYALTY SHARE OF ALASKA'S OIL AND NATURAL GAS. I FEEL AN OPEN PUBLIC DISCUSSION OF WHAT OUR POLICIES AS ALASKAN CITIZENS SHOULD BE IS ESPECIALLY GERMANE AT THIS TIME, AS THE BOARD ENTERS INTO CONSIDERATION OF HOW TO DERIVE MAXIMUM BENEFIT OF OUR ROYALTY SHARE OF PRUDHOE BAY OIL. ANY SALE OF THIS OIL WILL INDEED BE A MAJOR ACTION BY THE PEOPLE OF ALASKA, INVOLVING IN ALL LIKELIHOOD MORE THAN A BILLION BARRELS OF OIL AND POSSIBLY UPWARDS OF $10 BILLION. THE PEOPLE OF ALASKA ARE INDEED FORTUNATE THAT A GROUP SUCH AS YOURSELF HAS AGREED TO LEND YOUR CONSIDERABLE WISDOM AND EXPERTISE TO THIS SUBJECT, IN SOME CASES WITHOUT COMPENSATION WHATSOEVER. I CERTAINLY COMMEND THE PUBLIC MEMBERS OF THIS BOARD FOR THEIR DEDICATION TO THE PEOPLE OF ALASKA IN THESE IMPORTANT TIMES.

I HOPE WE CAN HAVE A USEFUL DISCUSSION TODAY REGARDING THE PRINCIPLES WHEREBY WE CAN, IN THE NAME OF THE PEOPLE OF ALASKA, BEST USE THIS GREAT AMOUNT OF MINERAL WEALTH THAT IS OURS BY VIRTUE OF THE ROYALTY PROVISIONS OF THE PRUDHOE BAY LEASES. I FEEL THAT THE PRINCIPLES THE BOARD AND THE LEGISLATURE ESTABLISH NOW, WITH THE HELP OF THE PEOPLE OF THE STATE, SHOULD APPLY TO ALL FORESEEABLE FUTURE USE OF ROYALTY OIL AND GAS. THEREFORE, IT IS EXTREMELY CRITICAL THAT WE DEFINE REALLY WHAT WE WANT TO GAIN FROM ANY DISPOSITION OF THIS OIL AND GAS.

AGO 533170

THE ALASKA PUBLIC FORUMS THAT I HAVE ATTENDED THROUGHOUT THE STATE HAVE, AS I AM SURE YOU ARE AWARE, ADDRESSED THIS VERY PROBLEM. MY PARTICIPATION IN THE FORUM HAS GIVEN ME SOME DEFINITE IMPRESSIONS REGARDING WHAT THE PEOPLE OF THE STATE WANT DONE WITH ROYALTY OIL AND GAS. THE PEOPLE'S UNDERLYING GOALS SEEM TO BE TO ENCOURAGE IN-STATE USE, AND WHATEVER POSITIVE DEVELOPMENTAL SPINOFFS MAY OCCUR FROM IT, SHORT OF SELLING AT CUT-RATE PRICES. THE PEOPLE, IT IS OBVIOUS TO ME, WANT TO ENCOURAGE HEALTHY INDUSTRY, AND DECIDEDLY DO NOT WISH TO ENCOURAGE INDUSTRY THAT MUST BE SUBSIDIZED FROM OUR NONRENEWABLE RESOURCE WEALTH (IN THE FORM OF REDUCED PRICE FOR ROYALTY OIL AND GAS). THEREFORE, I SUGGEST THAT THE BOARD NOT CONSIDER ANY SALES OF ROYALTY OIL AND GAS AT BELOW THE PRICE THE STATE WOULD GET WERE IT TO TAKE THE OIL OR GAS IN VALUE. THIS SHOULD BE THE BOTTOM LINE.

THIS, THEN, SHOULD BE OUR "BOTTOM LINE" REGARDING PRICING. BUT WHAT SHOULD THAT "BOTTOM LINE" BE REGARDING IN-STATE USE OF THE ROYALTY OIL AND GAS? I THINK BOTH THE STATUTE AND THE PEOPLE ARE VERY CLEAR ON THIS POINT: IN-STATE USES THAT PROVIDE A HEALTHY NET BENEFIT TO THE STATE AS A WHOLE SHOULD BE UNABASHEDLY ENCOURAGED. THOSE THAT PROVIDE A NET LOSS SHOULD NOT BE AIDED WITH OUR ROYALTY OIL AND GAS. IT IS BECOMING CLEAR THAT OUR ROYALTY OIL AND GAS PROVIDE NOT ONLY A VERY VALUABLE LIQUID ASSET, BUT ALSO AN EXTREMELY VALUABLE LEVER WHICH, IF WE ACT INTELLIGENTLY, WE MAY USE TO ENCOURAGE THE TYPES OF INDUSTRY WE ALL WANT IN THE STATE. THESE ARE THE INDUSTRIES THAT EMPLOY RESIDENT ALASKANS, THAT ARE CLEAN AND NOT POLLUTING, THAT RETURN TO THE PEOPLE OF THE STATE MORE IN TAXES AND OTHER BENEFITS THAN THEY TAKE FROM US IN INCREASED PUBLIC SERVICES, STATE PAYROLLS, CRIME, SOCIAL PROBLEMS, ETC.

AGO 533171

THERE CERTAINLY ARE INDUSTRIES THAT WILL PROVIDE A CLEAR NET BENEFIT TO ALASKANS, WHEN ALL ECONOMIC, SOCIAL, ENVIRONMENTAL, AND OTHER FACTORS ARE TAKEN INTO ACCOUNT, AND THESE ARE THE INDUSTRIES THAT WE SHOULD USE OUR ROYALTY OIL AND GAS TO ENCOURAGE.

I THINK THAT THE APPROACH BEFORE YOU IS A GOOD ONE. AS I UNDERSTAND IT, THIS APPROACH WOULD ASK ALL POTENTIAL PURCHASERS OF OUR PRUDHOE BAY OIL IN THIS CASE TO ANSWER A LONG SERIES OF TOUGH QUESTIONS. IN THEIR AGGREGATE, THESE ANSWERS WILL ALLOW US TO CALCULATE WHICH, IF ANY, OF THESE FIRMS IS OFFERING THE "DEAL" THAT IS IN THE BEST NET BENEFIT OF THE PEOPLE OF THE STATE, CONSIDERING ALL THESE FACTORS. I FEEL THAT THESE QUESTIONS SHOULD BE ASKED SPECIFICALLY, THAT THE ANSWERS CAN BE GIVEN WITHOUT PUTTING TOO MUCH EXTRA STRESS ON THE APPLICANTS, AND THAT THE DECISION CAN BE MADE PUBLICLY AND EXPEDITIOUSLY ONCE THE ANSWERS ARE IN. I HOPE THAT THE BOARD ADOPTS THIS APPROACH AND USES IT TO NEGOTIATE A SALE THAT IS CLEARLY IN THE NET BEST INTERESTS OF THE PEOPLE OF ALASKA.

I HAVE BEEN REPEATEDLY ASKED "DO YOU FAVOR A REFINERY IN ALASKA?" MY ANSWER HAS ALWAYS BEEN, YES I DO FAVOR A REFINERY IN ALASKA AS LONG AS IT PAYS ITS OWN WAY ON A NET BASIS, AND IS ENVIRONMENTALLY SOUND. I THINK THAT IF THE BOARD APPROACHES THESE POTENTIAL OIL PURCHASERS THROUGH THE METHOD OUTLINED ABOVE, WE WILL ALL KNOW VERY CLEARLY WHICH PROPOSALS WILL PAY THEIR OWN WAY AND ARE ENVIRONMENTALLY SOUND. I AM EQUALLY SURE THAT THE FACILITY WE ENCOURAGE THROUGH COMMITMENT OF OUR ROYALTY OIL WILL BE A VERY WELCOME CORPORATE CITIZEN OF THE STATE OF ALASKA.

AGO 533172

I HAVE ALWAYS FELT THAT A MAJOR PART OF ANY ROYALTY OIL OR GAS CONTRACT SHOULD BE THE BENEFITS THAT ALASKAN CITIZENS GAIN IN THE FORM OF LOWER PRICES FOR HEATING FUEL, GASOLINE, AIRCRAFT FUEL, WATERCRAFT FUEL, AND OTHER PETROLEUM PRODUCTS. IT HAS ALWAYS SEEMED TO ME A SINGULAR TRAVESTY THAT THE NATION'S MOST ENERGY-RICH STATE SHOULD PAY TWO-WAY TRANSPORTATION FOR OUR FUELS AND PETROLEUM PRODUCTS. I HAVE HEARD SEVERAL INTRIGUING SUGGESTIONS AS TO HOW IN-STATE PRODUCT PRICE MAY BE AFFECTED BY ROYALTY OIL AND GAS SALES, BUT DO NOT KNOW WHAT THE BEST ANSWER IS AT THIS POINT. I HAVE INSTRUCTED COMMISSIONER LERESCHE, AND WOULD HOPE THAT THE BOARD CONCURS, TO SEEK AN APPROPRIATE BENEFICIAL SOLUTION TO IN-STATE PRODUCT PRICES AS PART OF A LARGE SALE OF PRUDHOE OIL. I HOPE THAT THIS DOES NOT INVOLVE THE STATE ASSUMING ROLES, SUCH AS DISTRIBUTOR, WHICH MORE PROPERLY BELONG IN THE PRIVATE

AGO 533173

SECTOR, BUT WOULD HOPE THE BOARD CONSIDERS ALL SUGGESTIONS FOR SOLUTIONS TO THIS IN-STATE PRICE PROBLEM.

I MENTIONED BEFORE THAT OUR ROYALTY OIL IS A LEVER FOR ACHIEVING THE KIND OF GROWTH WE WANT IN ALASKA. AS A COROLLARY TO THIS, IT WOULD SEEM APPROPRIATE TO ME TO RESERVE THIS LEVER FOR USE WHERE IT DOES THE MOST GOOD. IN GENERAL, I WOULD EXPECT PERSPECTIVE PURCHASERS OF ROYALTY OIL AND GAS TO EXHAUST POSSIBILITIES OF PURCHASING OIL OR GAS FROM THE OTHER PRODUCERS, BEFORE THEY APPROACH THE STATE FOR OUR ONE-EIGHTH SHARE. IF WE DO NOT GRANT CUT-RATE PRICES, WHICH I THINK WE SHOULD NOT, THERE IS NO REASON FOR PERSPECTIVE PURCHASERS TO PREFER US TO OTHER PRODUCERS, AND I FEEL WE SHOULD RESERVE OUR ROYALTY PORTION FOR USE WHEN OTHER ALTERNATIVES ARE NOT AVAILABLE. I THINK IT ALSO FOLLOWS

FROM THIS THAT EXISTING FACILITIES IN-STATE, WITH EXISTING SUPPLY CONTRACTS, SHOULD NOT GENERALLY BE PURCHASERS OF OUR ROYALTY OIL AND GAS, UNLESS, OF COURSE, THEY EXPAND IN SUCH A WAY THAT MEETS THE NET BENEFIT CRITERIA WE HAVE ALREADY DISCUSSED. OF COURSE, PUBLIC UTILITIES ARE AN EXCEPTION TO THIS.

PUBLIC UTILITIES ARE NONPROFIT INSTRUMENTS OF THE CITIZENS OF ALASKA, AND THEREFORE SHOULD RECEIVE SOME MANNER OF SPECIAL TREATMENT FROM THE ROYALTY OIL AND GAS BOARD. I PERSONALLY FEEL, HOWEVER, THAT THIS SPECIAL TREATMENT SHOULD NOT INCLUDE SPECIAL CUT-RATE PRICING WHICH WOULD MERELY BE A SUBSIDIZATION OF CONSUMERS IN ONE AREA OF THE STATE AT THE EXPENSE OF THE POCKETBOOKS OF ALL ALASKANS. THERE ARE WAYS AROUND THIS WHICH THE LEGISLATURE MIGHT EXPLORE,

AGO 533174

INCLUDING ENERGY TAX CREDITS FOR ALL CITIZENS, DISCOUNTED BY THE AMOUNT OF LOCAL SUBSIDY TO PUBLIC UTILITIES THROUGH CUT-RATE ROYALTY OIL AND GAS PRICING, BUT UNTIL THESE ARE INSTITUTED, WE SHOULD GIVE NO SELECT GROUP OF ALASKANS SPECIAL TREATMENT OVER ALL OTHERS.

I DO FEEL, THOUGH, THAT PUBLIC UTILITIES SHOULD HAVE FIRST CALL ON ROYALTY OIL AND GAS AT THE GOING PRICE, AND THEREFORE THAT SOME REASONABLE PROPORTION SHOULD BE HELD FROM ANY LARGE-SCALE SALE OF PRUDHOE BAY ROYALTY OIL. IN ADDITION, I FEEL IT APPROPRIATE THAT MAXIMUM FLEXIBILITY IN VOLUME BE ALLOWED TO PUBLIC UTILITIES, WHEN SUCH FLEXIBLE VOLUME SALES ARE SMALL ENOUGH TO NOT DISRUPT THE ENTIRE ROYALTY OIL OR GAS PICTURE.

IN SUMMARY, OUR ROYALTY OIL AND GAS IS NOT ONLY A HUGE FINANCIAL ASSET, BUT ALSO A VERY SIGNIFICANT SOCIAL LEVER, WHEREBY WE MAY ENCOURAGE THAT HEALTHY TYPE OF ALASKAN INDUSTRY THAT SERVES TO THE BENEFIT OF US ALL, AND THAT WHICH ALL ALASKANS WELCOME INTO OUR STATE.

I VERY MUCH APPRECIATE THE OPPORTUNITY TO SHARE MY THOUGHTS WITH YOU THIS MORNING, AND HOPE WE CAN USE THE REST OF MY TIME TO DISCUSS IN DETAIL THE POINTS I HAVE MENTIONED OR ANY OTHER MATTERS YOU WOULD LIKE TO BRING UP.

THANK YOU VERY MUCH.

AGO 533175

ALASKA ROYALTY OIL AND GAS
In-State Use - A Developers Guide

DRAFT

Prepared For:
Alaska Royalty Oil and Gas Development Advisory Board

AGO 533176

INTRODUCTION

This guide includes the following components:

A. State Information Needs - Phase I Preliminary Submittal

B. State Information Needs - Phase II Pre-Proposal Submittal

C. Preliminary Siting Criteria

D. State Evaluation Factors

E. State Permitting Requirements

The purpose of the guide is to provide a means for improving the flow of information between the State and a prospective developer, in order to generate a mutually acceptable proposal for in-state facilities making use of Alaska's non-renewable resources. This is not a formal Request for Proposal, nor does it in any way supercede applicable State and local leasing, permitting or regulatory requirements. It is intended solely to:

1. ensure that the State receives, on a timely basis, the necessary information to evaluate a potential development;

2. provide a prospective bidder with information on how the State will be evaluating a project as well as some of the requirements and criteria that a developer will be expected to meet.

A. State Information Needs - Phase I Preliminary Submittal

The preliminary list includes basic types of information that a developer should provide the State in order to initiate the evaluation process. The State will utilize this information to perform a preliminary analysis of the proposed project. The State will make this evaluation available to the developer along with any additional questions and/or concerns.

B. State Information Needs - Phase II Pre-Proposal Submittal

Following the Phase I evaluation, a more detailed analysis of the potential project will be undertaken by the State. A prospective developer will be expected to provide a more specific set of information to satisfy the Phase II evaluation. After satisfactory completion of this phase, efforts can be geared to finalizing a mutually acceptable proposal package and, subsequently, a formal contract.

C. Preliminary Siting Criteria

In order to assist a developer in preparing a description of the proposed facility and locating potential acceptable sites, a preliminary set of State siting criteria is included in the guide.

D. State Evaluation Factors

The State will perform a formal two phase evaluation process. The particular areas of State concern, examples of evaluation factors and agency evaluation responsibilities are described in this internal document. This information should assist developers in understanding how their inputs will be utilized by the State, and the key factors of concern to the State. A more formalized comprehensive interagency project evaluation procedure is now in the process of being developed.

E. State Permitting Requirements

A draft inventory of State permits is included to assist the prospective developer in understanding the scope of required actions necessary prior to development activities. The applications for the appropriate State permits are not a part of the above information flow and evaluation process. If a proposal is accepted, formal applications must be submitted.

A working committee of key State personnel has been established to assist in the information exchange/evaluation process. This group will be available to respond to particular questions, clarify the procedures, provide available data (environmental standards and regulations, site-specific land uses, critical habitat areas, local socioeconomic characteristics, to name just a few), as well as to expedite State evaluation of a proposed project. Following is a tentative timing schedule of activities.

TIME TABLE

WEEKS

TASKS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
State provides Guide	●																					
ΦI Data	●	—	—	●																		
State ΦII Evaluation				●	—	—	—	●														
ΦII Data		—	—	—	—	—	—	—	—	—	—	●										
State ΦII Eval.												●	—	—	—	●						
Formal Proposal Subm.									—	—	—	—	—	—	—	—	—	△				
Contract Preparation												●	—	—	—	—	—	—	—	—	—	→

AGO 533179

INFORMATION NEEDS - DEVELOPER RESPONSIBILITIES

A. Phase I - Preliminary Submittal

B. Phase II - Pre-Proposal Submittal

A. INFORMATION NEEDS - DEVELOPER RESPONSIBILITY

PHASE I - PRELIMINARY SUBMITTAL

PHYSICAL CHARACTERISTICS

- General project description - site and logistical support requirements; type, pattern and timing of activities; project phasing; life of facility; product mix/volume;

- Site development concept; potential locations (general rationale) (see: Preliminary Siting Criteria)

- Power needs; raw material needs; access needs and transportation activities; construction material needs - General

- Water utilization requirements

- Technology scale-up requirements

ECONOMIC/FINANCIAL CHARACTERISTICS

- Estimated direct revenues to State and locality (source and timing)

- Financing and ownership schemes

- Labor demands - skills, full-time/part-time/seasonal, short-term/long-term

- Approaches to local and statewide hiring and training

- Preliminary estimates of availability and price of products and/or by-products for local and state-wide use

- Approaches/alternatives for sharing in the responsibility to: provide additional needed public facilities and services; provide in-state service industries; compensate or offset potential negative environmental, economic and fiscal impacts to State and locality

- General information on contribution to local and State economy

- Estimates of type and quantity of inputs demanded by industry

- Expected contributions of State and/or locality - land, infrastructure, tax incentives, below-market-price raw materials, etc.

ENVIRONMENTAL CHARACTERISTICS

- General environmental implications and conflicts expected

- Projected discharges and emissions

- Overview of mitigation strategies/alternatives - spills contingency, air pollution control, site protection, solid waste and waste water disposal, toxic and hazardous substance control, erosion control, etc.

MISC.

- Data collection and study plans and schedule

- Public participation schemes

- Plans for joint government (State and Local) and developer planning and study efforts

B. INFORMATION NEEDS - DEVELOPER RESPONSIBILITY

PHASE II - Proposal Submittal

PHYSICAL CHARACTERISTICS

- Alternative site locations and designs and recommended site and design (with rationale and statement of why recommended site and design are superior)
- Project description (from design to close-down) - specific site and logistical support requirements; operational (including expansion or contraction) plans; product mix/volume; site development plans; provisions for protective or buffer zones
- Readjusted (if necessary) power needs; raw material needs; access needs, transportation loads, density and frequency of transportation activities, types of vehicles and/or vessels; communications requirements; construction material utilization plan and potential sources
- Water consumption and utilization plans; potential sources/conflicts
- Specific technology scale-up requirements
- Convertibility of facilities for other uses (bulk storage, industrial park); potential concurrent uses of facilities (general cargo area, recreational facilities); conversion schemes
- Prior site and construction material negotiations with local landowners/government

ECONOMIC/FINANCIAL CHARACTERISTICS

- Direct revenues to State and locality (timing and sources)
- Updated financing and ownership plans; opportunities for local equity participation
- Updated labor demands - skills, job classifications, full-time/part-time/seasonal, short-term/long-term
- Local and state-wide hiring and training (management and high skills) plans (including phasing and construction/operation separation)
- Refined estimates of availability and price of products and by-products; marketing schemes and/or commitments
- Prior negotiations with suppliers, distributors, transport services, unions

- Commitments for sharing in the responsibility to: (1) provide additional needed public services and facilities; (2) provide in-state service industries; (3) compensate or offset potential negative environmental, economic and fiscal impacts to the State and locality; (4) provide adequate monitoring, surveillance and quality control programs

- Specific expected State and/or local contributions--land, tax incentives, below-market-price raw materials, low-cost power, etc.

ENVIRONMENTAL CHARACTERISTICS

- Volume and timing of all discharges and emissions

- Degree of dredging required (if any) and proposed disposal plans and locations

- Probable primary and secondary impacts; probable adverse effects which cannot be avoided; anticipated irretrievable commitment of resources

- Mitigation strategies - spills contingency; air pollution control; site protection; solid waste and waste water management; revegetation, reclamation and/or restoration schemes; erosion control; stream protection; etc.

- Visual impacts; potential noise and dust problems

- Adequacy (at recommended site) of soils and local geology for solid waste and sewage disposal

- Recycling and conversion schemes; energy conservation and alternative energy use strategies

MISC.

- Monitoring, surveillance and quality control strategies

- Estimates of energy efficiency of project

- Data collection and analysis plans and schedule - base line data; environmental and engineering studies; technology assessment; risk analysis; EIS preparation

- Perceived or expected external constraining factors - Federal permits, NEPA, political opposition, land claims, etc.

- Cost breakdown including: estimated capital/construction/ operating costs; training programs; public participation; studies; etc.

- Initial schedule for public inputs (on proposal and potential sites)

- Non-resident employee orientation program plans

C. PRELIMINARY SITING CRITERIA

AGO 533185

C. PRELIMINARY SITING CRITERIA

The following preliminary siting criteria can be utilized to assist a prospective developer in: (1) locating potential sites; (2) responding to the information needs of the State:

1. Compatibility - Ensure that facility sites are compatible with existing and projected land and water uses;

2. Consolidation - Utilize existing sites and facilities that are capable of handling anticipated demand while meeting the other siting criteria;

3. Traffic - Avoid siting facilities where the most likely vehicular and/or vessel route(s) would interfere with: community activities; population centers; fishing and/or harbor operations;

4. Access - Facilities should be sited such that access to navigable waterways and recreational areas shall not be foreclosed;

5. Safety - Site fuel, crude oil and LNG storage and transfer areas: downwind from populated areas to reduce the hazard of fire and explosion to humar population; at elevations sufficiently above mean sea level to escape the highest tsunami run-up;

6. Pipelines - Align pipeline routes away from active faults, areas of subsidence, glacial surge;

7. Resource Protection - Site facilities so that areas of particular historic, agricultural, scenic, recreational and unique environmental, wildlife habitat, and cultural values will be protected;

8. Site Preparation - Avoid sites where extensive site clearing, dredging and construction in productive wetlands, estuaries, deltas or other sensitive areas would be required;

9. Environmental Management - Site facilities in areas of least biological productivity, diversity and uniqueness and where effluents, emissions and spills can be controlled or contained easily;

10. Air Quality - Site facilities where the probability of chronic air quality problems would be low;

11. Water Quality/Supply - Site facilities where the probability of water quality degradation would be low and where the existing water supply would not be adversely affected;

12. Local Preference - Locate facilities where local preferences are supportive of such development.

D. Examples of State Evaluation Factors

ECONOMIC CONSIDERATIONS

AREA OF CONCERN

Impact on governmental resources and responsibilities

EVALUATION FACTORS (Examples)

- net governmental fiscal balance over time--local and state-wide (particularly revenue shortfalls)
- change in quality and quantity (per capita) of public services or goods
- long-term convertability of facilities for public or private use; potentials for concurrent use

AGENCY RESPONSIBILITY

Department of Revenue, Department of Community and Regional Affairs, Division of Budget and Management, Department of Public Works, Department of Highways

---

AREA OF CONCERN

Direct contribution to local and state-wide private economy (includes changes resulting from the development itself and activities accompanying it due to expanded markets)

EVALUATION FACTORS (Examples)

- change in real per capita income and product (due to project and attendent service facility expansions)
- short- and long-run price impacts (e.g. short-run shortages of private goods or facilities; long-run private economies of scale, increased competition, changes in transportation costs)

AGENCY RESPONSIBILITY

Department of Commerce and Economic Development, Department of Revenue

ECONOMIC CONSIDERATIONS

AREA OF CONCERN

Employment

EVALUATION FACTORS (Examples)

- change in local and regional (% and #) employed, unemployed, under-employed Alaskans
- type, level and salaries of jobs
- time characteristics of jobs and their distribution (short- vs. long-term)
- level of training and Alaska hire commitment (amount of labor imported)
- degree to which manpower training dovetails with timing of employment requirements

AGENCY RESPONSIBILITY

Department of Labor, Department of Commerce and Economic Development, Department of Community and Regional Affairs

---

AREA OF CONCERN

Distributional aspects and implications of the development

EVALUATION FACTORS (Examples)

- distribution of income and jobs associated with the project among groups (in-state vs. out-of-state; local vs. state-wide, current residents vs. in-migrants; Native/non-Native; income classes; sectors of the economy)
- opportunities for local (participation--investment)
- ownership of assets (in-state vs. out-of-state)
- changes in land value and ownership

AGENCY RESPONSIBILITY

Department of Community and Regional Affairs, Department of Revenue, Department of Labor, Department of Commerce and Economic Development

ECONOMIC CONSIDERATIONS

AREA OF CONCERN

Indirect or spinoff economic activities (the primary project's impact on future economic developments)

EVALUATION FACTORS (Examples)

- the possibility of related developments (either producing inputs for the production process of the primary industry or utilizing outputs of the primary industry)
- size and impact of such development (measured in ways similar to economic impact of primary industry)

AGENCY RESPONSIBILITY

Department of Commerce and Economic Development, Department of Community and Regional Affairs, Department of Revenue

SOCIAL

AREA OF CONCERN

Lifestyle changes and social conflicts

EVALUATION FACTORS (Examples)

- the potential for value conflicts between local residents and expected in-migrants
- potential for cross-cultural conflicts between local residents and expected in-migrants
- conflict with subsistence use of wildlife
- growth management capability
- degree of local control and self-determination
- impact on quality of rural lifestyle or village lifestyle amenities
- public sentiment (local and state-wide)

AGENCY RESPONSIBILITY

Department of Community and Regional Affairs, Department of Health and Social Services, Department of Education, Department of Fish and Game

COMPATIBILITY WITH PLANS, PROGRAMS AND POLICIES

AREA OF CONCERN

Natural resources and land use alternatives

EVALUATION FACTORS (Examples)

- impact on forest sustained yield
- impact on fishery resources/areas of high biologic-commercial productivity
- impact on mineral extraction (including oil and gas)
- impact on available water supply
- impact on agricultural potentials
- impact on fish and wildlife habitats/populations
- impact on recreational potentials
- impact on wilderness, historic, scenic and sensitive environmental areas
- construction material demands

AGENCY RESPONSIBILITY

Department of Natural Resources, Department of Fish & Game, Department of Environmental Conservation, Department of Commerce and Economic Development

AREA OF CONCERN

Safety and Health

EVALUATION FACTORS (Examples)

- air, water and noise pollution (degree of localization; impact on human settlements, environmentally sensitive areas, highly scenic areas)
- dust, spills, thermal discharges (same as above)
- safeguards for transport and storage of toxic and hazardous substances
- drainage pattern impacts
- adequacy of soils and local geology for solid waste and sewage disposal
- compliance with State, local, and Federal environmental standards and criteria

AGENCY RESPONSIBILITY

Department of Environmental Conservation, Department of Fish and Game, Department of Natural Resources, Department of Health and Social Services

---

AREA OF CONCERN

Environmental Management

EVALUATION FACTORS (Examples)

- monitoring, surveillance and quality control strategies
- development time frame (to build up environmental protection capabilities)
- degree of commitment of irretrievable resources and/or irreversible consequences
- environmental data sufficiency
- degree of internalization of environmental costs

AGENCY RESPONSIBILITY

Department of Environmental Conservation, Department of Fish and Game

TECHNICAL CONSIDERATIONS

AREA OF CONCERN

Construction feasibility/probability of construction delays/cost overrun potentials

EVALUATION FACTORS (Examples)

- technology requirements
- data base/engineering studies sufficiency
- infringement on high hazard areas
- legal and/or regulatory constraints
- degree of consolidation/concentration of facilities
- external constraints (political, economic, logistic)
- expansion potentials
- energy efficiency of project/energy conservation measures
- use of alternative energy sources

AGENCY RESPONSIBILITY

All departments

E. STATE PERMITTING REQUIREMENTS

TABLE OF CONTENTS

I. Permits issued by the Department of Environmental Conservation

1. Waste Water Disposal Permit
2. Solid Waste Disposal Permit
3. Air Emissions Permit
4. Pesticides Permit
5. Surface Oiling Permit
6. Open Burning Permit

II. Permits issued by the Department of Fish and Game

7. Anadromous Fish Protection Permit
8. Critical Habitat Areas Permit
9. State Game Refuge Land Use Permit

III. Permits issued by the Department of Highways

10. Encroachment Permit
11. Utility Permit
12. Driveway Permit
13. Overweight - Oversize Permit

IV. Permits issued by the Department of Natural Resources

A. Parks and Recreation and Public Use - Special Land Use Permits

14. Investigation and Collection Permit
15. State Park Incompatible Use Permit
16. Access Routes Permit

B. Oil and Gas Permits - Drilling Permits

17. Drilling Permit
18. Drilling Deviation Permit

C. Oil and Gas - Regulatory Orders

19. Well Spacing Permit
20. Notice of Abandonment
21. Plugging Procedure
22. Well Marker
23. Water Wells
24. Temporary Abandonment
25. Location Cleanup
26. Multiple Completion of Wells
27. Commingling of Production
28. Earthen Reserviors
29. Disposal of Brine of Other Wastes

D. Oil and Gas - Plan of Operations

30. Additional Recovery Methods

E. Oil and Gas - Coal Conservation

31. Development Work

F. Land and Waters - Leasing of Lands

32. Right-of-Way or Easement Permit
33. Special Land Use Permit

G. Land and Waters - Tide and Submerged Lands

34. Tidelands Permit
35. Tideland Right-of-Way and/or Easement Permit
36. Limited Personal Use Permit

H. Land and Waters - Water Use

37. Permit to Appropriate Water
38. Dam Construction
39. Application for Preferred Use

I. Land and Waters - Timber

40. Use of Timber and Materials
41. Authorization for Transportation Facilities

J. Land and Waters - Materials Sales

42. Special Material Use Permit

K. Land and Waters - Mineral Leasing

43. Noncompetitive Procedures
44. Coal Prospecting Permit
45. Sodium Leasing Method
46. Potassium Leasing Method
47. Geothermal Resources Leasing Method

L. Land and Waters - Offshore Permits

48. Tide and Submerged Lands

M. Land and Waters - Millsites

49. Surface Use Permit

N. Land and Waters - Forest Protection

50. Burning Permit

O. Land and Waters - Miscellaneous Land Use

51. Operations on State Land Requiring Permits
52. Subleases of State Lands
53. Right-of-Way Permit
54. Abandonment of or Reduction or Impairment of Services of Pipeline by Leasee Carrier
55. Applications for Right-of-Way Leases and Certificates
56. Preservation of Archaeological Resources

Appendix A - Department of Environmental Conservation Contacts List

Appendix B - Department of Fish and Game Contacts List

Appendix C - Department of Highways Contacts List - District Engineers

Appendix D - Department of Highways Contacts List - Overweight-Oversize Permit Contacts

Appendix E - Department of Natural Resources Contacts List

Permits Issued by
the Department of Environmental Conservation

1. Waste Water Disposal Permit

A person conducting any operation which results in the disposal of solid or liquid waste material into the waters or onto the lands of the State must procure a permit from the Department of Environmental Conservation before disposing of the waste material. The permit must be obtained for direct disposal and for disposal into publicly operated sewerage systems. The permit does not apply to persons discharging only domestic sewage into the sewerage system.

Procedure: Permit applicant should contact the Department of Environmental Conservation Regional Environmental Supervisor. See Department of Environmental Conservation "Contacts List" in appendix.

Requirements: The Department may require the submission of plans for sewage and industrial waste disposal or treatment or both for publicly or privately owned or operated industrial establishments, community, public or private property subdivision or development.

Authority for Permit:
* AS 46.03.100. Waste disposal permit.
* AS 46.03.090. Plans for pollution disposal.
* AS 46.03.110 and 720. Waste disposal permit procedure.
* 18. AAC. 72.030. Pretreatment.

Criteria for Issuance: AAC Title 18, Chapter 70 and 72.

2. Solid Waste Disposal Permit

No person may establish, modify or operate a solid waste disposal facility without a permit, except the following:

1) a single family or duplex residence on which solid waste is generated and disposed of, on-premises;

2) a farm on which solid waste generated from the operation of that farm is disposed; and

3) incinerator facilities having a total rated capacity of less than 200 pounds of solid waste per hour.

Procedure: Permit applicant should contact the Department of Environmental Conservation Regional Environmental Supervisor for appropriate forms. Application for permit shall contain:

1) completed permit application forms;

2) detailed plans and specifications for facility;

3) certification of compliance with local ordinances and zoning requirements;

4) a report detailing the proposed methods for operation, population of area to be served, characteristics, quantity and source of material to be processed; and

5) 60 days public notice and public hearing.

Requirements: Detailed plans and specifications for the facility are required, as outlined above.

Authority for Permit:
* AS 46.03.020. Powers of the department.
* AS 46.03.100. Waste disposal permit.

Criteria for Issuance: AAC Title 18, Chapter 60, Solid Waste Management.

3. Air Emissions Permit

A permit is required to operate a facility capable of emitting quantities of pollutants injurious to human health or welfare, animal or plant life or property.

Procudure: Applicant should contact the Department of Environmental Conservation Regional Supervisor.

Requirements: No person may construct or modify a facility requiring a permit to operate until detailed plans and specifications are submitted to the Department and approved.

Authority for Permit:

* AS 46.03.010. Declaration of policy.
* AS 46.03.140. Emission control requirements.
* AS 46.03.150. Classification and reporting.
* AS 46.03.160. Additional contaminant control measures.
* AS 46.03.170. Variances.
* 18 AAC 50.120. Permit to operate.

Citeria for Issuance:

* 18 AAC 50.020. Ambient Air Quality Standards.
* 18 AAC 50.030. Open Burning.
* 18 AAC 50.040. Incinerators.
* 18 AAC 50.050. Industrial Processes and Fuel Burning Equipment.
* 18 AAC 50.120. Permit to operate.

4. Pesticides Permit

No person may, without a permit issued by the Department, apply or cause to be applied any pesticide or broadcast chemical.

Procedure: The permit applicant should contact the Department of Environmental Conservation Regional Environmental Supervisor for the appropriate form.

Requirements: An application for a permit to use pesticides shall include information relating to the name of the pest to be controlled, the type of formulation to be used, and percentage of active ingredients, the quantity of active ingredients to be applied per unit area, and other information.

Authority for Permit:
* AS 46.03.320. Authority.
* AAC Title 18, Chaper 90. Pesticide and Broadcast Chemical Control.

Criteria for Issuance:
* AAC Title 18, Chapter 90. Pesticide and Broadcast Chemical Control.

5. Surface Oiling Permit

No person may discharge, cause to be discharged, or permit the discharge of oil, asphalt, bitumen or a residuary product of petroleum onto the lands of the State unless that person has been granted a surface oiling permit.

Procedure: Applicant should contact the Department of Environmental Conservation Regional Environmental Supervisor for the appropriate form.

Requirements: An application for a surface oiling permit shall be made on forms prescribed by the Department and shall contain information considered necessary to the Department.

Authority for Permit:
* 18 AAC 75.010. Surface Oiling Permit.
* AS 46.03.020. Powers of the Department.
* AS 46.03.740. Oil pollution.

Criteria for Issuance:
* AAC Title 18, Chapter 75.

6. Open Burning Permit

Open burning for disposal of oils, oily waters, asphalts and tars and similar wasted materials is prohibited unless conducted under a permit from the Department.

Procedure: Applicant should contact the Department of Environmental Conservation Regional Environmental Supervisor.

Requirements: Emission data may be required prior to grant of the permit.

Authority for Permit:
* AS 46.3.020. Powers of the Department.
* 18 AAC 50.030. Open Burning.
* 18 AAC 50.120. Permit to Operate.

Criteria for Issuance:
* 18 AAC 50.020. Ambient Air Quality Standards.

Permits Issued by
the Department of Fish and Game

7. Anadromous Fish Protection Permit

If a person or governmental agency desires to construct a hydraulic project, or use, divert, obstruct, pollute, or change the natural flow or bed of a specified river, lake or stream, or use wheeled, tracked, or excavating equipment or log-dragging equipment in the bed of the specified river, lake, or stream, the person or governmental agency shall notify the Department of Fish and Game before the beginning of the construction or use.

Procedure: Permit applicant should contact the Department of Fish and Game Regional Habitat Supervisor for his region. See Department of Fish and Game "Contacts List" in appendix.

Requirements: If the Commissioner of the Department of Fish and Game determines to do so, he shall require the person or government agency to submit to him full plans and specifications for the proper protection of fish and game in connection with the construction or work, or in connection with the use, and the approximate date the construction or work or use will begin, and shall require the person to obtain written approval from him as to the sufficiency of the plans and specifications before the proposed construction or use is begun.

Authority for Permit:
* AS 16.05.870. Protection of Fish and Game.
* 5 AAC 95.010. Waters important to Anadromous Fish.

Copies of the List of Waters Important to Anadromous Fish or of information contained therein may be obtained by writing the Lieutenant Governor or the Department of Fish and Game, Habitat Protection Section, Subport Building, Juneau, Alaska, 99801, or may be obtained from ADF&G Regional Habitat Supervisors.

8. Critical Habitat Areas Permit

Before the use, lease or other disposal of land under private ownership or State jurisdiction and control, within State Fish and Game critical habitat areas, the person or responsible State department or agency shall notify the Department of Fish and Game.

Procedure: The responsible person should contact the Department of Fish and Game Regional Habitat Supervisor for his region.

Requirements: If the Board of Fish and Game so determines, it shall instruct the Commissioner to require the person or governmental agency to submit full plans for the anticipated use, full plans and specifications of proposed construction work, complete plans and specifications for the proper protection of fish and game, and the approximate date when the construction work is to commence, and shall require the person or governmental agency to obtain the written approval of the Commissioner as to the sufficiency of the plans and specifications before construction is commenced.

Authority for Permit:
* AS 16.20.250. Multiple land use.
* AS 16.20.260. Submission of plans and specifications.

Criteria for Issuance:
Determination of Board of Fish and Game.

9. State Game Refuge Land Use Permit

Where the use, lease or disposal of real property in State game refuges is under the control or jurisdiction of the State, whether through Federal permit or State ownership, the responsible State department or agency shall notify the Department of Fish and Game before initiating any use, lease or disposal of real property.

Procedure: The responsible State department or agency should contact the Commissioner of the Department of Fish and Game.

Requirements: If the Commissioner so determines, he may require the person or governmental agency to submit full plans and specifications for the anticipated use, full plans and specifications of proposed construction work, complete plans and specifications for the proper protection of fish and game, and the approximate date when the construction work is to commence, and shall require the person or agency to obtain written approval of the Commissioner as to the sufficiency of the plans and specifications before construction is commenced.

Authority for Permit:
* AS 16.20.050. Multiple land use.
* AS 16.20.060. Submission of plans and specifications.

Criteria for Issuance:
Determination of the Commissioner.

Permits Issued by
the Department of Highways

10. Encroachment Permit

An encroachment may be constructed, placed, changed or maintained across or along a highway but only in accordance with regulations adopted by the Department. No encroachment may be constructed, placed, maintained or changed until it is duly authorized by a written permit issued by the Department of Highways.

Procudure: Applicant should contact the Department of Highways District Engineer for his region. See Department of Highways "Contact List" in appendix.

Requirements: During routine maintenance patrol, road and weather condition inspection, or at regular intervals as deemed necessary, maintenance personnel shall inspect right-of-way for encroachments. When an encroachment is found, District Right-of-Way will make a recommendation to the District Engineer as to whether the encroachment should be permitted or removed.

Authority for Permit:
* AS 19.25.200. Encroachment permits.

Criteria for Issuance: State of Alaska Department of Highways Standard Operating Procedure, S.O.P. #0000-14.

11. Utility Permit

An electric transmission, telephone, or telegraph line, pole line, railway, ditch, sewer, water, heat, or gas main, flume, or other structure which by law may be constructed, placed or maintained across or along a highway by a person or political subdivision may be maintained or constructed only in accordance with regulations prescribed by the Department. No utility project of this nature may be undertaken until it is authorized by a written permit issued by the Department.

Procedure: Applicant should contact the Department of Highways District Engineer in his region.

Requirements: Plans are required.

Authority for Permit:
* AS 19.25.010. Use of right-of-ways for utilities.
* 17 AAC 15.010. Application for utility permit.
* 17 AAC 15.020. Utility Permit.

Criteria for Issuance: See Alaska Administrative Code 17 AAC 15.010-020.

12. Driveway Permit

Before starting the construction of driveways or performing any work upon the right-of-way, the property owner shall first apply for and obtain a revocable permit from the Department of Highways.

Procedure: Applicant should contact the Department of Highways District Engineer for his region.

Requirements: Applicant must perform all work in accordance with permit.

Authority for Permit:
* 17 AAC 10.020. Driveways and Road Approaches.
* AS 19.05.020. Regulations.

Criteria for Issuance:
* 17 AAC 10.020. Driveways and Road Approaches.

Driveway Regulations can be obtained at Department of Highways District Offices.

13. Overweight - Oversize Permit

The Department of Highways, with respect to highways under its jurisdiction, may:

1) establish limitations on weight and load of vehicles;

2) issue special written permits authorizing the operation of overweight vehicles; and

3) prohibit the operation or impose restrictions on vehicular use of highways during certain seasons of the year.

Procedure: Applicant should contact the Department of Highways District Office for application form 14-156.

Requirements: Permits may be issued for operation of oversize-overweight vehicles when:

1) Application has been made in writing, good cause has been shown and all pertinent requirements are met;

2) The applicant has completely described his load and vehicle route and time of travel;

3) The applicant has certified that the load cannot "reasonably" be dismantled or disassembled to meet the legal load and size requirements. Disassembly may be required by the District Engineer to assure the safety of the traveling public or the highways and its appurtenances;

4) The applicant has affirmed that the vehicle or vehicles meet all requirements of the Alaska Department of Commerce and the Transportation Commission; and

5) The proposed move will not be detrimental to the public safety or damage the roadway structure or bridges as determined under State requirements.

Authority for Permit:

* AS 19.10.060. Regulation of weight and load of vehicles and use of highways during certain seasons.
* AS 28.05.020. Authority for Commissioner of Highways to adopt regulations.
* 17 AAC 25.010. Penalty and Exclusion.
* 17 AAC 25.020. Width of Vehicles.
* 17 AAC 25.030. Height and Length of Vehicles and Loads.

Criteria for Issuance: * 17 AAC 25.010-030.

Alaska Oversize and Overweight Permit Movements State of Alaska, Department of Highways, Maintenance Division, P. O. Box 1467, Juneau, Alaska, 99802.

AGO 533212

Parks, Recreation and Public Use - Special Land Use Permits

14. Investigation and Collection Permits

A person qualified under 11 AAC 16.040 may apply to the director upon an application form provided by him for a permit to investigate or collect historic, prehistoric or archaeological resources of the State.

Procedure: Applicant should contact the Department of Natural Resources District Office. See "Contacts List" in appendix.

Requirements: Person must qualify as having some experience in anthropology or field archaeology.

Authority for Permit:
* AS 41.20.040. Division within Department of Natural Resources.
* AS 41.35.050. Regulations.
* AS 41.35.080. Permits.
* 11 AAC 16.030. Investigation and Collection Permits.

Criteria for Issuance:
* 11 AAC 16.040. Qualified Person.

15. State Park Incompatible Use Permit

Incompatible uses (e.g., mineral exploration, cutting of timber) of public lands within a State park are allowable only with a permit. Permits will be issued where it is determined that the ecology of the area will not be damaged and public use values will be protected.

Procedure: Applicant should contact the Department of Natural Resources District Office.

Requirements: Contact District Office.

Authority for Permit:
* AS 41.20.020. Duties of Department of Natural Resources.
* AS 41.20.040. Division within Department of Natural Resources.
* 11 AAC 18.010. State Park Incompatible Uses.

Criteria for Issuance:
* 11 AAC 18.010. State Park Incompatible Uses.

16. Access Routes Permit

A permit is required to gain an access route across State park land or water to privately owned property wholly or partially within a State park.

Procedure: Contact the Department of Natural Resources District Office.

Requirements: Permittee must construct access route according to specifications provided by the director.

Authority for Permit:
* AS 41.20.020. Duties of the Department of Natural Resources.
* AS 41.20.040. Division within the Department of Natural Resources.
* 11 AAC 18.020. Access Routes.

Criteria for Issuance: Determined by Director of Parks and Recreation.

17. Drilling Permits

A person wishing to drill or deepen any well for oil and gas must first submit an application accompanied with a fee of $100.00, and then obtain permit.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division. See "Contacts List" in appendix.

Requirements: $100.00 fee. A survey plat must accompany the application showing the precise location of the drilling activity.

Authority for Permit:
* AC 31.05.090. Permits and fees to drill wells.
* 11 AAC 22.005. Permit to Drill or Deepen.

Criteria for Issuance:
* 11 AAC 22.005. Permit to Drill or Deepen.

18. Drilling Deviation Permit

A permit is required before a well operator may intentionally deviate from the vertical, except for the purposes of straightening the hole, side-tracking junk, or correcting mechanical difficulties.

Procedure: Contact the Department of Natural Resources - Minerals and Energy Division.

Requirements: Application for permit shall include:

1) surface and proposed producing interval locations in terms of distances from lease and section boundaries;

2) reason for deviation;

3) list of affected operators and a showing that each has been furnished a copy of the application by certified mail, or a showing that the applicant is the only affected operator; and

4) neat and accurate plat of lease and all affected operators and the surface and proposed producing interval locations as well.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.050. Deviation.

Criteria for Issuance:
* 11 AAC 22.050. Deviation.

19. Well Spacing Permit

A person must apply for and receive an exception to the well spacing regulations before deviation from the regulations is allowed.

Procedure: Permit applicant should contact the Department of Natural Resources Minerals and Energy Division.

Requirements: An application must indicate the affected operators, and include a plat of the proposed action.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.055. Well Spacing.

Criteria for Issuance:
* 11 AAC 22.055. Well Spacing.

20. Notice of Abandonment

Before beginning work on any well, notice of intention to abandon must be filed, and approval must be given.

Procedure: Person should contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Notice must show the reason for abandonment and must be accompanied by a detailed statement of proposed work including such information as kind, location, size of plugs, and plans for mudding, etc.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.100. Notice.

Criteria for Issuance:
* 11 AAC 22.100. Notice.

21. Plugging Procedure

To deviate from the plugging procedure set up in the regulations, approval upon application must be obtained.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Follow procedures outlined in 11 AAC 22.110., Plugging Procedures.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.110. Plugging Procedure.

Criteria for Issuance:
* 11 AAC 22.110. Plugging Procedure.

22. Well Marker

In order to waive well marker requirements, the surface owner must request and receive approval.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Contact Minerals and Energy Division.

Authority for Permit:
* AS 31.05.030. Powers and Duties of the Department.
* 11 AAC 22.120. Well Marker.

23. Water Wells

Written authority for a well to be used as a fresh water well must be applied for and approved.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Contact Minerals and Energy Division.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.140. Water Wells.

24. Temporary Abandonment

Approval is required if a well is to be temporarily abandoned.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: If approved, a plug must be placed at the top and bottom of the well casing in such a manner as to prevent the intrusion of any foreign matter into the well. The well shall be left full of mud.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.150. Temporary Abandonment.

25. Location Cleanup

Time extension must be obtained for the well operator to deviate from the cleanup regulations.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Contact the Minerals and Energy Division.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.170. Location Cleanup.

26. Multiple Completion of Wells

No well may be put into multiple production without approval.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Approval will require evidence of adequate and complete separation as ascertained by pressure or circulation tests.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.210. Multiple Completion of Wells.

27. Commingling of Production

An order approving commingling in the same well bore of production from two or more wells must be obtained before such practice is permitted.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Proposing operator must certify that contact has been made with the affected parties and no opposition is furnished to committee within 15 days.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.215. Commingling of Production.

28. Earthen Reservoirs

Permission must be obtained to store oil in earthen pits.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Contact Minerals and Energy Division.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.220. Earthen Reservoirs.

29. Disposal of Brine and Other Wastes

Permission is required for the disposal of salt water.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: It must be shown that the disposal of salt water will not contaminate fresh water or endanger other natural resources.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.250. Disposal of Brine and Other Wastes.

Note: The items listed under the above heading involve the need for administrative approvals and orders from the Oil and Gas Conservation Committee. These approvals on various well operations are, in effect, permits to do various types of work once a well is completed or to abandon a well. However, the forms and procedures do not bear the title permit.

30. Additional Recovery Methods

A permit is required for any method of pressure maintenance or methods of additional recovery used other than primary recovery techniques.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Application must contain a plat showing the unit, lease or group of leases within the proposal project, along with other related information.

Authority for Permit:
* AS 31.05.020. Waste Prohibited.
* 11 AAC 22.400. Application.

31. Development Work

No development work shall be done on coal deposits on State lands without the advance approval of the State geologist.

Procedure: Contact the Department of Natural Resources - Minerals and Energy Division.

Requirements: Contact the Minerals and Energy Division.

Authority for Permit:
* AS 27.20.005. Purposes.
* AS 27.20.010. Rules and Regulations.
* 11 AAC 46.010. Advance Approval.

32. Right-of-Way or Easement Permit

The Division of Lands Director may issue permits for roads, trails, ditches, pipelines, drill sites, log storage, telephone and transmission lines or similar uses or improvements.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: Plats are required, as well as an application fee.

Authority for Permit:

* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.035. Powers and duties of the Director.
* AS 38.05.075. Leasing procedures.
* AS 38.05.330. Permits.
* 11 AAC 58.200. Right-of-Way or Easement Permit.

33. Special Land Use Permit

The Director of the Division of Lands may issue special land use permits on such terms and conditions as he deems to be in the interests of Alaska.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: Provide information as to the nature of the proposed activity.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.035. Powers and duties of the Director.
* AS 38.05.075. Leasing procedures.
* 11 AAC 58.210. Special Land Use Permit.

34. Tidelands Permit

The Director of the Division of Lands may issue permits for the improvement or use of State-owned tidelands, or for personal use of materials. The first preference in the granting of such permits will be granted to the upland owner over other nonpreference applicants for the use of tideland and contiguous submerged land seaward of the upland property.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: A $20.00 filing fee is required. Upon receipt of the application, the Director shall, within 60 days, express his approval or disapproval, and shall state his reasons. Each upland owner may protest the issuance of the permit. No permits shall be issued that will deny the upland owner reasonable access to tide waters during the course of or completion of the work.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.320. Occupied tidelands and submerged lands.
* 11 AAC 62.710. Tidelands Permits.

Criteria for Issuance:
* 11 AAC 62.720. Application for Tideland Permits.

35. Tideland Right-of-Way and/or Easement Permits

Permits may be issued by the Division of Lands Director for secondary roads, trails, ditches, pipelines, telephone transmission lines, log storage, oil well drilling sites, and production facilities for the purposes of recovering minerals from adjacent lands under valid lease and other similar uses or improvements. First preference shall be granted to the upland owner.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: An applicant must furnish the name and address of the upland owner.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.320. Occupied Tidelands and submerged lands.
* 11 AAC 62.810. Tidelands Right-of-Way and/or Easement Permits.

Criteria for Issuance:
* 11 AAC 62.810. Tideland Right-of-Way and/or Easement Permits.

36. Limited Personal Use Permit

Permits may be granted for a limited quantity of materials for personal use, and such materials shall not be sold. The director shall, in each permit, specify the quantity of material allowed but in no event shall the quantity exceed 100 cubic yards. The permits are for temporary use only.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.020. Authorities and duties of the Commissioner.
* AS 38.05.320. Occupied Tidelands and submerged lands.
* 11 AAC 62.820. Limited Personal Use Permit.

37. Permit to Appropriate Water

Any person who desires to appropriate otherwise unappropriated waters of the State shall make application for a permit to appropriate water.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: An application for a permit to appropriate water shall include:

1) location of source from which water is to be appropriated;

2) place where the appropriated water will be of beneficial use;

3) quantity of water to be appropriated;

4) proposed use of water to be appropriated; and

5) description of the proposed means of diversion.

Authority for Permit:

* AS 46.15.040. Right to appropriate.
* AS 46.15.060. Existing rights.
* AS 46.15.070. Notices; objections.
* AS 46.15.135. Determination of existing rights.
* AS 46.15.180. Crimes.
* 11 AAC 72.050. Application for Permit to Appropriate.

38. Dam Construction

An application for a permit to appropriate water must include plans and specifications for any dam that may be built.

Procedure: Applicant must contact the nearest District Office of the Department of Natural Resources.

Requirements: Plans are required. If necessary, the Director may request that the applicant obtain an independent appraisal of the plans and specifications from a qualified engineer acceptable to the Director.

Authority for Permit:

* AS 46.15.040. Right to appropriate.
* AS 46.15.060. Existing rights.
* AS 46.15.070. Notices; objections.
* AS 46.15.135. Determination of existing rights.
* AS 46.15.180. Crimes.
* 11 AAC 72.060. Dam Construction.

39. Application for Preferred Use

The holder of a preferred use status may make an application for a permit to appropriate either unappropriated or previously unappropriated waters or both.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: A $20.00 filing fee is required. The applicant must provide the names and addresses of all holders of existing water rights, permits to appropriate or certificates of appropriation whose rights to water would be reduced, or in times of water scarcity, could be reduced by the diversion of water to the preferred use. Also required are certified copies of executed agreements between the holder of preferred use status and all other persons names as required to provide compensation for loss of previously appropriated water, or certified copies of any court orders which direct the amount and manner of compensation paid.

Authority for Permit:

* AS 46.15.040. Right to appropriate.
* AS 46.15.060. Existing rights.
* AS 46.15.070. Notices; objections.
* AS 46.15.135. Determination of existing rights.
* AS 46.15.180. Crimes.
* 11 AAC 72.160. Application for Preferred Use.

40. Use of Timber and Materials

Gravel, sand, and rock used by a purchaser in connection with a sale of timber may be acquired under a special permit issued in connection with the timber sale.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:

* AS 38.05.020. Authorities and duties of the Commissioner.
* AS 38.05.110. Sale of timber and materials.
* AS 38.05.115. Limitations and conditions of sale.
* AS 38.05.120. Disposal procedure.
* 11 AAC 76.185. Use of Timber and Materials.

41. Authorization for Transportation Facilities

Timber purchasers must obtain a permit for use of tidelands under State jurisdiction which are necessary for dumping, sorting, storage and rafting of timber cut from State sales.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Location and design of roads or access will be approved by the Director prior to construction.

Authority for Permit:

* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.110. Sale of timber and materials.
* As 38.05.115. Limitations and conditions of sale.
* AS 38.05.120. Disposal procedure.
* 11 AAC 76.205. Authorization for Transportation Facilities.

42. Special Material Use Permit

The Director may issue special material use permits for periods not to exceed one year upon such terms and conditions as he deems to be in the interest of the State.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.115. Limitations and conditions of sale.
* AS 38.05.120. Disposal procedure.
* 11 AAC 76.540. Special Material Use Permit.

43. Noncompetitive Procedures

Applications for noncompetitive leases on permits for a mineral may be filed on any noncompetitive lands opened for leasing of that mineral.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.135. Generally.
* AS 38.05.145. Leasing Procedure.

44. Coal Prospecting Permit

A permit is required for prospecting or exploration work necessary to determine the existence of coal deposits in an unclaimed and undeveloped area. The permit is for a period of two years, and not to exceed 5,120 acres.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.035. Powers and duties of the Director.
* AS 38.05.145. Leasing procedure.
* AS 38.05.150. Coal.
* 11 AAC 84.115. Prospecting Permits Operations.

45. Sodium Leasing Method

Prospecting permits for lands not known to contain valuable deposits of sodium are issued noncompetitively.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 30.05.145. Leasing procedure.
* 11 AAC 84.400. Sodium Leasing Method.

46. Potassium Leasing Method

Prospecting permits authorized for lands not known to contain valuable deposits of potassium compounds are issued noncompetitively.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.145. Leasing procedure.
* 11 AAC 84.600. Potassium Leasing Method.

47. Geothermal Resources Leasing Method

Prospecting permits authorized for lands which have not been classified as geothermal resources areas are issued noncompetitively.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.145. Leasing procedure.
* 11 AAC 84.700. Geothermal Resources Leasing Method.

48. Tide and Submerged Lands

The exclusive right to prospect for deposits of minerals in or on tide and submerged lands may be granted by the Director of the Division of Lands.

Prodecure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Applicant must meet qualifications outlined in AS 38.05.190.

Authority for Permit:

* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.250. Tide and submerged lands.
* 11 AAC 86.500; 510; 530; and 540. Permit Applications, Acceptable Permit Work, Conversion of an Offshore Prospecting Permit to a Mining Lease, and Lease Rental.

49. Surface Use Permits

A permit is required for millsite and tailings removal.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: A reasonable rate or fee schedule shall be charged for such use.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.255. Surface use.
* 11 AAC 86.600. Millsites.

50. Burning Permit

A burning permit is required during the fire season for the burning of any materials in the area designated by the Department of Natural Resources.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: The applicant shall provide information as to the type, location, size and person in charge of the burning; the area and material to be burned; and the number of persons controlling the burn. Prior to the issuance of the permit, an inspection may be required of the area to be burned.

Authority for Permit:
* AS 41.15.050. Fire Season.
* 11 AAC 92.010. Permit.

51. Operations on State Land Requiring Permits

A permit is required for the following activities on State lands: 1) activity requiring; a) the use of explosives; b) the use of hydraulic prospecting or mining equipment and/or methods; c) drilling to a depth in excess of 300 feet; and (2) activity which the Director of the Division of Lands determines may result in harm to lands having special scenic, historic, archaeological, scientific, biological, recreational or special resource value.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.035. Powers and duties of the Director.
* 11 AAC 96.010. Operations Requiring permits.

52. Subleases of State Land

A permit is required from the Director of the Division of Lands prior to the sublease or assignment of any portion of State-leased land.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.095. Subleases.

53. Right-of-Way Permits

The Director of the Division of Lands may issue permits, right-of-ways or easements on State land for secondary roads, trails, ditches, transmission lines and distribution pipelines, field-gathering lines, telephone and transmission lines, log storage, oil well drilling sites, and production facilities for the purposes of recovering minerals from adjacent lands under valid lease, and other similar uses or improvements for the limited use or timber or materials.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permits
* AS 38.05.330. Permits.

54. Abandonment of or Reduction or Impairment of Service of Pipeline by Leasee Carrier.

No leasee may abandon or reduce or impair service of any portion of a pipeline that is on State land or subject to lease without first receiving a certificate from the Commissioner that the action is in accordance with the terms of the lease.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Contact the Minerals and Energy Divison.

Authority for Permit:

* AS 38.35.030. Abandonment of, or reduction or impairment of, service of pipeline by leasee carrier.

55. Applications for Right-of-Way Leases and Certificates

Persons desiring to own a pipeline which is proposed to be located in whole or in part on State land shall apply for a noncompetitive right-of-way lease of this land and a certificate that the construction, operation, transportation, service, or sale is in accordance with the lease.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit

* AS 38.35.050. Applications for right-of-way leases and certificates.

56. Preservation of Archaeological Resources

If the State archaeologist determines that archaeological sites or remains will be adversely affected by public construction, the project cannot commence until the State archaeologist performs necessary investigations.

Procedure: Contact the Division of Parks and Recreation.

Requirements: Contact the Division of Parks and Recreation.

Authority for Permit:

* AS 41.35.070. Perservation of historic, prehistoric, and archaeological resources threatened by construction.

Developer's Guide - Appendix A

Department of Environmental Conservation Contacts List

Central Office
Department of Environmental
Conservation
Pouch O
Juneau, Alaska 99811

Northern Regional Office

Doug Lowery
Regional Environmental Supervisor
Department of Environmental
Conservation
P. O. Box 1601
675 Seventh Avenue
Fairbanks, Alaska 99707

Phone: 452-1714

Southcentral Regional Office

Kyle Cherry
Regional Environmental Supervisor
Department of Environmental
Conservation
Rm. 1206, MacKay Building
338 Denali Street
Anchorage, Alaska 99501

Phone: 274-5527

Prince William Sound Regional Office

Randy Bayliss
Regional Environmental Supervisor
Department of Environmental
Conservation
Pouch E
Valdez, Alaska 99686

Phone: 835-4698

Southeast Regional Office

Deena Henkins
Regional Environmental Supervisor
Department of Environmental
Conservation
Pouch OA (Mayflower Building, Dougla
Juneau, Alaska 99811

Phone: 364-2165

Developer's Guide - Appendix B

Department of Fish and Game Contacts List

Region I

Rick Reed
Regional Supervisor
Habitat Protection Section
Department of Fish and Game
210 Ferry Way
Juneau, Alaska 99801

Phone: 586-6630

Region II

Tom Trent
Habitat Protection Section
Department of Fish and Game
333 Raspberry Road
Anchorage, Alaska 99502

Phone: 344-0541

Region III

J. Scott Grundy
Regional Supervisor
Habitat Protection Section
Department of Fish and Game
1300 College Road
Fairbanks, Alaska 99701

Phone: 452-1531

Developer's Guide - Appendix C

Department of Highways Contacts List

District Engineers

Southeastern - Region III

Wallace K. Williams
Southeastern District Engineer
Department of Highways
6860 Glacier Highway
P. O. Box 3-1000
Juneau, Alaska 99802

Phone: 789-0841

Central - Region I

Jack M. Spake
Central District Engineer
Department of Highways
5700 Tudor Road
P. O. Box 6750
Anchorage, Alaska 99502

Phone: 337-1511

Interior - Region II

H. Woodrow Johansen
Interior District Engineer
Department of Highways
2301 Peger Road
Fairbanks, Alaska 99701

Phone: 452-1911

Southcentral - Region V

Rowe D. Redick
Southcentral District Engineer
Department of Highways
P. O. Box 507
Valdez, Alaska 99686

Phone: 835-4322

Western - Region IV

Henry Springer
P. O. Box 1048
Nome, Alaska 99762

Phone: 443-5266

Developer's Guide - Appendix D

Department of Highways Contacts List

Overweight-Oversize Permit Contacts

Central - Region I

John Bates
Department of Highways
5700 Tudor Road
Anchorage, Alaska 99502

Phone: 337-1511

Interior - Region II

Ronald Doner
Department of Highways
2301 Peger Road
Fairbanks, Alaska 99701

Phone: 452-1911

Southeastern - Region III

Dick Hamilton
Department of Highways
P. O. Box 3-1000
Juneau, Alaska 99802

Phone: 789-0841

Western - Region IV

Ron Davena
Department of Highways
P. O. Box 220
Nome, Alaska 99762

Phone: 443-5266

Southcentral - Region V

R. A. Walker
Department of Highways
P. O. Box 506
Valdez, Alaska 99686

Phone: 835-4322

AGO 533259

Developer's Guide - Appendix E

Department of Natural Resources Contact List

Southeast Land District Office

Henry Lee Hall
Division of Lands
Department of Natural Resources
Pouch M
Juneau, Alaska 99811

Phone: 465-2415

Southcentral Land District Office

Lawrence A. Dutton
Division of Lands
Department of Natural Resources
323 East Fourth Avenue
Anchorage, Alaska 99501

Phone: 279-5577

Northcentral Land District Office

William Copeland
Department of Natural Resources
State Office Building
Room 116
Fairbanks, Alaska 99701

Phone: 479-2243

Department of Natural Resources
Minerals and Energy Division

Easy Gilbreth
Minerals and Energy Division
Department of Natural Resources
323 East Fourth Avenue
Anchorage, Alaska 99501

Phone: 274-8542

AGO 533260

PLEASE NOTE: THE PRECEDING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

SCOMM

#14:7

Alaska State Legislature

POUCH Y, STATE CAPIT
JUNEAU, ALASKA 99
907 465-3800

TRANSCRIPT OF TESTIMONY OF

ALPETCO ATTORNEYS

March 20, 1978

BEFORE THE SPECIAL COMMITTEE ON ROYALTY OIL AND GAS

Committee:

Senators:	Representatives:
Chairman, Mike Colletta	Chairman Bill Miles
Pat Rodey	Charley Parr
Bill Sumner	Chat Chatterton
John Sackett	Joe McKinnon
Kay Poland	Al Osterback

(First Portion of Tape Indiscernible Due to Poor Quality of Tape)

MR. ROGERS:

I believe that's the main management. If you have any questions about any of the individuals I'll try to answer them for you. I think they have various responsibilities. I will have an annual report sent to you.

CHAIRMAN MILES

Okay, I would appreciate that.

CHAIRMAN MILES:

Mr. Rogers can you tell me in the contract where it says that ALPETCO has to process 150,000 barrels a day?

MR. ROGERS:

No, there's no requirement that we have to process 150,000 barrels a day. There is a requirement that we -- the feeling there was that because of the lack of knowledge about the configuration of the plans and because of the concern that once we got the plant in operation we would have what is now planned to be a two and half billion motivation to keep the plant operating, we have no economic interest in expending two and a half billion dollars to have 150,000 barrels a day coming at us. We are concerned that we might want, for reasons of our own, to shut portions of the facility down to add on facilities to shut down to realign the facilities or something like that. We did not want to have a 20 year period of time in which we had an obligation to keep the (indisc.) running. I think Commissioner LeResche was satisfied that if we did sink

all of the dollars in a minimum of a billion five, that we would have plenty of reason to continue the operation of the facility. Our lenders would certainly not lend us the money, except on the basis of the continued operation of the facility.

CHAIRMAN MILES:

Aside from the 30,000 barrels a day (indisc.), is there a requirement to process anything else in the contractual -- in this contract?

MR. ROGERS:

I think it's implied that if we build a petrochemical facility and put a billion and a half dollars in it, it has got to process something and the current configuration on that is to process 60 to 90,000 barrels of crude oil and fuel oils per day. Only a part of it can go into petrochemicals and the rest for in-state fuels. So to answer your question directly, no there is no requirement --the requirement that we process a certain amount of barrels. There's only a requirement that we continue the operation, but if we follow the criteria of 10.1, excuse me, 10.2, and meet those criteria -- those are the bench marks, so called bench marks -- if we meet the general requirements to construct the facility which is Article 4, the two of those together should satisfy. I think you just have to assume that economic common sense will prevail. A lot of comfort was received by Commissioner LeResche in knowing that if we got a billion and a half financing commitment and if we got 70% take or pay contracts, the rest would all follow and to require a certain minimum production of us, require continued operation, was really an unnecessary thing to do once we passed the point of no return so to speak.

CHAIRMAN MILES:

Representative McKinnon.

MR. McKINNON:

On those same lines, if it turns out that you only -- for some reason or another -- you take 120,000 barrels a day, is the State obligated to supply an additional 30,000 barrels a day? (Indisc.-- simultaneous speech)

MR. ROGERS:

Yes, literally under the contract there is and the principle reason for that is that there may be a period of time in which there is a -- for instance a shutdown of the line. It was suggested during the negotiations that the production delivered be limited to that which paralleled the amount of processing going on in the facility. But we asked that that not be imposed because we are planning a 30 day storage at the site and there will be an amount of storage in great big quotes, in transit so that if the pipeline froze or shut down for an extended period of time, we would have enough storage and enough in process of delivery from Valdez to wherever we're going -- could be even at Valdez, that we would be able to survive

AGO 559310

for that 30 day period. Once everything was turned back on, we would want to (indisc.) as much as we possibly could not only to feed the refinery but to replenish that backlog of the feed stock storage. So we couldn't really tie the production to the -- the deliveries to the production.

MR. McKINNON:

If it did turn out that (indisc.) level of use was 120,000 barrels a day, would the State still be obligated to provide the additional 30,000 barrels per day if ALPETCO, for instance, wanted to take the oil for whatever other purposes they had for it (indisc. -- simultaneous speech)

MR. ROGERS:

Under the pricing formula I think there's no reason why we would. We frankly are having serious concerns whether we'll ever take interim delivery before the petrochemical facility is operating. The pricing under the contract is never going to be below market and can and probably will operate to result in an aggregate price in excess of market and we were told that the brokerage of oil allows for such a narrow margin that there would be no future in (indisc. -- cough). We're in the business of trying to build this petrochemical refinery and it's a very different business that we're going in. I don't think there's much motivation to go into spot sales of 30,000 barrels a day. I think under the contract it's possible.

MR. PRATT:

There's one other -- Mr. Chairman, may I comment?

CHAIRMAN MILES:

Mr. Pratt.

MR. PRATT:

There's one other answer to your question -- it would be no, you don't have 150,000 barrels a day, we wouldn't get any more than 120 if that's all you had.

MR. ROGERS:

Well that's all we had --

MR. PRATT:

-- (indisc. -- simultaneous speech) the answer you were looking for originally but that's another facet of the answer.

MR. ROGERS:

Well we had 120,000 barrels.

MR. PRATT:

(Indisc.)

MR. ROGERS:

Even if we had other sources or other --

MR. PRATT:

If you only had 120,000 in royalty oil, that's all we get. Am I not correct in that?

MR. ROGERS:

I think technically under the contract we have the right regardless of the present need of the refinery, we have the right to call for up to 150,000 barrels.

MR. PRATT:

But I'm saying if there were only 120,000 (indisc. -- simultaneous speech)

MR. ROGERS:

Yeah, I see, what Henry is saying is that under present circumstances the proposed favored customer clause will never come into effect if the State does not decide to sell any oil cheaper than they're selling to us. 2.4 will not come into operation if there's no in-kind oil available at (indisc.) and if only 120 is coming out at the end of the line, that's all we'll get and to that extent that's correct. And that we're going to have to live with. I'm not answering your question, am I?

MR. McKINNON:

No, you haven't. (Indisc.)

MR. ROGERS:

(Indisc. -- simultaneous speech) We've always heard of that as present design is 150,000 barrels per day. The possibilities of it being scaled down are off in the future and I really can't assist (indisc.-- cough) talking about it presently. If it is scaled down, it results in a change in a section under the contract and a change of intent on our part and literally under the contract we could have 120,000 barrels a day refining capacity and still require 150,000. But in negotiations it was not required because

everybody felt that there would be no economic motivation on our part to call for that extra 30 unless we needed it for extra storage or something like that.

CHAIRMAN MILES:

Representative Osterback.

MR. OSTERBACK:

Thank you Mr. Chairman. What else would you be -- the question asked there today on your petrochemical plant, you also get material for making nylon rope (indisc.), would there be any chance -- would you be interested in that or would that have to be a separate contract or do you plan on adding to your plant?

MR. ROGERS:

Again, I'm just repeating things that I've heard from my clients. I think the contracts I've written mention in products of that nature that our facility as such is not going to produce end products like that but we're hopeful that we can arrange the purchaser base in a manner that the purchaser might be interested in buying the products out of our facility and next door build an end product use factory. But I do not believe we're going to be doing end product, particularly final finished products, we're (indisc.) building blocks.

MR. OSTERBACK:

But there would be material available for it?

MR. ROGERS:

Yes, hopefully that's what will help -- will further industry in the area and location of the facility.

MR. OSTERBACK:

Well I don't know if anyone's familiar with it here but when you're talking about the bottom fish now -- the nylon rope and polyethylene, the plastic bags which you use on crab buoys -- we're buying them from Norway now at about $50.00 apiece, a 15" bag. By the time you pay $10.75 a pound for gillnet (indisc.) and nylon rope is about the same, you take a big (indisc.) line or crab buoy line, it literally runs into thousands and thousands of dollars just for one boat.

MR. ROGERS:

Mr. Spitz at Chem Systems, I think, was in the ALPETCO story, you can see the different demands for the feed stocks and I think that that economic problem exists all along the West Coast.

AGO 559313

MR. OSTERBACK:

Yes, we're importing most of our stuff. And if the State could go into a deal like this, if (indisc.) follow up on, I think (indisc.) on this contract right here.

MR. ROGERS:

And reduce the consumer's prices. If the volume -- the only thing that might limit it is the potential volume. If the volume is there, it becomes economical, surely someone will come in and do something of that nature.

MR. OSTERBACK:

I imagine the volume (indisc.) now. I don't know how much it would take to (indisc.)

MR. ROGERS:

(Indisc.)

MR. OSTERBACK:

And the price -- you just take nylon -- oh from something like $3.00 a pound to $10.75 in the last three years. You don't know where it's going to stop. (Indisc.) for a drift gillnet (Indisc.) a hundred pounds. And about $360.00 three years ago and now it costs us over a $1000 dollars.

MR. ROGERS:

All your nets are made out of petrochemical products.

MR. OSTERBACK:

Right, nylon and ---

MR. ROGERS:

You'd think there'd be a huge market for that.

MR. OSTERBACK:

Now your rope, there's no more manila rope or (indisc.) rope made any more, it's all nylon or polypropylene and (indisc.) as far as I know and I don't know much about it. But I know if we get into the bottom fish industry, there's a big demand for that type of thing. Because all of that is synthetic and everything.

MR. ROGERS:

Um humh.

MR. OSTERBACK:

Even your cable is (indisc.).

MR. ROGERS:

(Indisc.)

MR. OSTERBACK:

So much steel and so much polypropylene to make it kind of flexible. So that's what I wanted to know if you guys ever thought of anything like that.

MR. ROGERS:

Well we have thought of it in the context of letting further industry develop, that maybe it's economical for them to do it. It's not part of the present project. We've got our hands full trying to get this facility up.

CHAIRMAN MILES:

Mr. Rogers, under the clause, you know at ALPETCO we asked them if they would take lower priced oil at the same terms and conditions. If the legislature would approve the contract before it, would it thereby be foregoing any options in future contracts -- should you exercise an option to take other (indisc.) in your legal opinion, translated into labor (indisc.)

MR. ROGERS:

First of all, (indisc.) facility as an operation, you can sell your oil -- you can give the oil away until that's the case. The concern stems from us putting in a 2.5 million dollar facility and then the state selling a significant quantity of oil to people it's not presently dealing with. The Tesoro contract is excluded and of course the North Pole is exluded and selling that oil at a subsidy price at a later date in a manner that would destroy our competitive market. We're making a promise that we will build a facility and that we'll service in-state needs and we feel that this will do a lot of good things for the State of Alaska and the (indisc.) for that is just to ask you that if you do decide to sell oil, you're going to sell it all day long at the same (indisc.) price you're selling it to us at. The one area in which that is not true is that the price formula under Article 2.3 is a formula price that figures in not only what you're selling your oil for but the computed transportation costs. In simple terms it means that if there is a sale of Cook Inlet oil at an in-value price, we will probably under 2.3 be able to purchase that oil because it will be at a lower gate price. Fred Boness refers to it as a gate price which is a good term. All 2.3 says is that if the price at the gate of Prudhoe oil is higher than the gate price of the oil from Cook Inlet or wherever, then we have the right of first refusal basically. We have the right to take that oil in place of the Prudhoe oil we're buying and that will allow us the competitive ability to continue operations of our facility.

CHAIRMAN MILES:

What I'm asking is, by approving this contract, let's say you exercise that option that you just laid out (indisc. -- airplane)

the terms and conditions as it was offered by the state. Does the legislature still have the power to say yea or nay as it does right now on oil and gas sales or would we be getting supplied --

MR. ROGERS:

Yes, it certainly would.

CHAIRMAN MILES:

We would still be able to say --

MR. ROGERS:

You would still have the decision to sell or not sell. All we're saying here is that if you decide to sell, if you did decide to sell, and you decide to sell at a lower adjusted price, then we get the right of first refusal. You're talking about 2.3, aren't you? This is the most favored customer clause. We are not interfering with the legislature's right to approve any contracts, it's just a matter for your concern as to who the purchaser is.

CHAIRMAN MILES:

What would happen if in that case you took oil or determined it was wrong to take oil under another set of facts and the legislature said no?

MR. ROGERS:

Then we would stay where we are. The party at that point in time would be that we would still be drawing oil down under the Prudhoe agreement. There's a six month notification procedure under the Prudhoe agreement and there are some notice requirements -- I'm not familiar with in all of your leases and so nothing would ever happen until the legislature approved or disapproved. If it disapproved then we'd all just be left where we were in the beginning.

CHAIRMAN MILES:

I see. It wouldn't be a court battle that ties up any sale or anything.

MR. ROGERS:

No, sir. We have no right to the oil unless a decision is made to sell it. I don't see on what grounds we could file any suit. We have no -- the legislature's authority is pretty clear. We just want to be the purchaser. We do not want to interfere with any of the procedural aspects of the sale, particularly the legislature's authority to say yea or nay.

CHAIRMAN MILES:

So you don't envision any court fight over it. Did you want to comment on that Elke?

MS. KALLAB:

AGO 559316

Just very quickly. When you say not to destroy the competitive

price, you know, that's provision 2.3. Of course it is possible to have a competitor bid an in-value price, (indisc.-cough) lower transportation costs, you might wind up with a lower price and thereby you become entitled under 2.3. Conversely then, of course, in order for anybody else to purchase that oil, they would have to give a premium to the state, is that correct?

MR. ROGERS:

Yes, all of this assumes a totally imperfect (indisc.) market. If everything's working right there will never ever be any difference, but we know that doesn't always prevent ... The answer to your question is yes. (Indisc. -- loud traffic noise)

MS. KALLAB:

(Indisc.-- loud noise) and to, you know, be fair, you would conceivably ask somebody else to give premiums so that you can continue to pay for in-value.

MR. ROGERS:

If the state was smart they'd sit there and figure out the gate price as one way, and the other way and they'd say okay, we're going to offer this for a premium of "x" dollars and ALPETCO in an exercise of it's economic judgment would say well we'd rather have that oil and it would be one of the rare instances in which the state would be able to get a premium and everybody would walk away happy.

CHAIRMAN MILES:

Representative McKinnon.

MR. McKINNON:

The uppermost question you presented -- if ALPETCO exercises its option, a new contract would have to be presented to the legislature. And the legislature would have to -- and the legislature turns it back. Now you're saying there'd be no court cases involved. The state then went on to once again attempt to dispose of the royalty oil. What would the situation be? Would ALPETCO then still have first option which would have to go back to the legislature?

MR. ROGERS:

Yes, sir. As long as that process, a lower adjusted price, continues ... (interrupted)

MR. McKINNON:

Then theoretically the oil could never be sold unless . . .

MR. ROGERS:

Well that's where the philosophical rub comes. The question is does -- will the legislature not want the oil to be sold ALPETCO? Will they not be able to find a purchaser that will pay the same price. We have a right of first refusal. It is going to be difficult to give a subsidy price to another competitor. There are obvious ways to get around it, you can sell the oil at the price and then grant them a monitary subsidy if you get into business development and things of that sort. We are worried more about (indis-. -- cough) subsidy that would be represented by the lower price.

MR. McKINNON:

The contract requires that the royalty oil be offered under the same terms and conditions. Taking a hypothetical -- say the state decides to release Kachemak Bay. There's a discovery and a substantial amount of royalty oil. And that royalty oil was offered on the condition that it be used for a refinery on the Homer Spit. Now would ALPETCO be obligated to accept that royalty oil under those same terms?

MR. ROGERS:

Would ALPETCO have an option?

MR. McKINNON:

Well if they exercised the option, would they be required to build a refinery on the Homer Spit?

MR. ROGERS:

Oh, yes.

MR. McKINNON:

Okay --

MR. ROGERS:

I would think so.

MR. McKINNON:

Under those conditions then ALPETCO just couldn't exercise its option to take the oil --

MR. ROGERS:

To take the oil and leave it, no sir. Not at all.

CHAIRMAN MILES:

Representative Chatterton.

MR. CHATTERTON:

Thank you, Mr. Chairman. Let's run this over again a little bit for me. The legislature if there is outside -- whatever you want to call it -- royalty oil, state royalty oil from Cook Inlet or any place. If the only time that the legislature would become involved is a determination as to whether to take that royalty oil in-kind or in-value. Now, if the legislature determines to take it in-kind, there would be no legislative approval be necessary for you to exercise, as I conceive it, for you to exercise the option under 2.3. The legislature's not involved other than they don't approve this contract.

MR. ROGERS:

Pardon my ignorance but aren't all oil and gas contracts subject to legislative approval?

MR. CHATTERTON:

This is a contract right here and the terms of 2.4, I guess, yeah 2.4, I'm sorry, if the legislature approves this contract why other than -- the legislature will never be involved again; except in the determination that the yet to be discovered royalty oil in-value or in-kind. We would have no approval -- we are not in any position to say yea or nay to you.

MR. ROGERS:

I'm totally out of my field of practicing here -- Alaska law. But I don't think that there's a sale of oil under 2.3 until the legislature has approved the contract. I don't --

MR. CHATTERTON:

-- approve of this contract.

MR. ROGERS:

No, approve future sales contracts.

MR. CHATTERTON:

Would you show me that? Where the law is?

MR. ROGERS:

The way the law reads, I don't think --

MR. CHATTERTON:

Present law says you (indisc.) the right to approve any contract for the sale of royalty oil. Any contract.

MR. ROGERS:

This is only making up to 150-- this is already in the contract that you have.

MR. CHATTERTON:

I understand that, but when somebody elses contract comes along you have the right to approve their contract. But I can't approve their contract because you've got the oil.

MR. ROGERS:

Alright, let me make --

MR. CHATTERTON:

You don't have to answer it now, but you should look into it. I read this 2.4 --

MR. ROGERS:

Let me make sure -- you're on 2.4, we're on 2.3, maybe that's the reason

MR. CHATTERTON:

Well 2.3 is almost the same thing. We're giving you the right of first refusal in both things on any royalty oil.

MR. ROGERS:

I think on 2.4 you have a valid concern. On 2.3, I don't think -- there's certainly is no intention and I don't think the terms put along side the statutory requirement of legislative approval would permit ALPETCO to buy any oil under 2.3 without further legislative approval.

MR. CHATTERTON:

Alright --

MR. ROGERS:

Under 2.4, I think your concern might be expressed by having the in-kind requirement, we have the ability to prevent sales in the future.

MR. CHATTERTON:

I think we do, but I don't know. But I will yield to you on 2.3 and I'm sorry. You're right on 2.3.

CHAIRMAN MILES:

I think Mr. Berry (ph) had a comment.

MR. BERRY:

Well initially I was having the feeling that you were talking about two different agreements.

MR. CHATTERTON:

I think that's what was happening, I apologize.

MR. BERRY:

I think one way of thinking in 2.4 is that you confuse this contract with having sold 150,000 barrels a day.

MR. CHATTERTON:

(Indisc.)

MR. BERRY:

And insofar as it's necessary to take oil from other leases to make that 150,000 barrels a day that has been sold by this contract and it wouldn't be subject to legislative approval or disapproval.

MR. CHATTERTON:

Correct. And from a completely practical standpoint, we'll always be in this position. I doubt if there's ever more than 150,000 barrels of royalty oil coming from state lands 5 years down the road.

MR. BERRY:

To the extent that that's the case, it has been sold by this contract and it would not end up being before the legislature again.

MR. CHATTERTON:

That's correct. Mr. Chairman.

CHAIRMAN MILES:

Mr. Chatterton.

MR. CHATTERTON:

With your permission, I'd like to (indisc.) Maybe the fastest way for me, rather than asking -- getting around asking questions, is to suggest to you a scenario and have you tell me that this contract won't let me do it. Can we do it that way?

MR. ROGERS:

Sure.

MR. CHATTERTON:

Okay. My scenario is this and this is despite the language set forth in -- oh whatever it is -- 4.2, I believe. Despite the language set forth there, (indisc.) obligations. My scenario is that I believe that if I were ALPETCO and I was so inclined despite my best good intentions to build a world scale petrochemical plant in Alaska which is what the intentions of both parties are. But then I come to the contract and I say well things aren't going so good and so I say that I'm going to make the necessary expenditures to build a 30,000 barrel a day feed stock products refinery, middle of the barrel products, and so forth and so on, typical Alaska market products, jet fuel, and I'm going to get some letters that say that I can honestly, at the drop of a hat, go and borrow 1.5 billion dollars at any time that I want to, just by picking up the phone. And I go a little further --

MR. ROGERS:

(Indisc.)

MR. CHATTERTON:

Yeah. I have my letter to show that I am financable for the world scale petrochemical plant and I got mad at the end of the 18 months term. At the end of 36 months I have a nice little refinery taking 30,000 barrels a day. At the end of 18 months I'm already exchanging or selling, or something, fuel, my 150,000 barrels a day. At the end of 36 months say, or something like that, I'm running 30,000 of it through my refinery and sending the other 120,000 barrels a day on south and making money doing that and I don't plan to go any further than that. Now would you show me that that doggone guy over there called seller can break this contract? Will you show me --

MR. ROGERS:

Yes, I can show you one -- first the assumption in my mind is it's not feasible economically, -- (indisc.--simultaneous speech)

MR. CHATTERTON:

Are you an attorney, or are you a financial --

MR. ROGERS:

I'm an attorney. (Indisc. -- simultaneous speech)

MR. CHATTERTON:

Let's don't argue that point.

MR. ROGERS:

The question has been asked before and the continual response of our

AGO 559322

people is that you cannot build a fuel refinery for a billion and a half dollars. A fuels refinery --

MR. CHATTERTON:

I don't have to spend any billion and a half dollars.

MR. ROGERS:

In the contract.

MR. CHATTERTON:

Show me in the contract. I don't want the economics. I want you to show me in the contract that I can't --

MR. ROGERS:

10.2 (9) gets to that point.

MR. CHATTERTON:

It doesn't quite. Unless I can't read the English language. But go through that (indisc.) by seller steps. It's on page 31. I guess that's a good place to start. Keep in mind my scenario. I'm going to have a 30,000 barrel a day products refinery and I'm going to have a letter of credit for 1.5 billion dollars and I'm going to be taking 150,000 barrels a day of oil and I'm going to run 30,000 through the refinery and I'm going to ship 120,000 south. I want you to show me the language in this contract that lets the state cancel it.

MR. ROGERS:

At that point.

MR. CHATTERTON:

At any point that the state realizes that I don't plan to build a world scale petrochemical plant.

MR. ROGERS:

But we still have to (indisc.) ourselves in economic reality.

MR. CHATTERTON:

No we don't. I'm looking for contract language that gives the state an oppor--at what point and under what conditions could the state terminate this contract?

MR. ROGERS:

How much have we spent at that point?

AGO 559323

MR. CHATTERTON:

I think we've only spent about 600 million dollars.

MR. ROGERS:

Okay, that's at the 36 months.

MR. CHATTERTON:

At 36 months -- keep in mind that that's not what you have spent, part of that 600 million is what you have spent and the other part is what any political subdivision has spent.

MR. ROGERS:

Right.

MR. CHATTERTON:

It's the sum of the two.

MR. ROGERS:

If you'll make a note, I'll explain how that came into being.

MR. CHATTERTON:

(Indisc.--simultaneous speech)

MR. ROGERS:

To answer your question, the next termination point would be twelve months later, if we had not expended a billion dollars. At that point, by the preparatory language in 10.2, the contract is automatically terminated--no further action of any state official and we're sitting there with a 600 million dollars fuels refinery with no feed stocks.

MR. CHATTERTON:

Okay supposing with my scenario, I got to that point and the state proceeded to terminate. I had my little plant. I'd spent my six hundred million dollars, or my share of the 600 million, and all of this and I didn't plan to go any further and the state comes-- the Commissioner of Natural Resources says on this 48 months "we're canceling your contract". What recourse would I have if I didn't want the contract canceled?

MR. ROGERS:

It's specifically provided that the Commissioner does not have the authority to prevent the termination from occurring. He has certain authority to extend, particularly to allow ALPETCO

to go to the legislature but he can't stop the termination of the contract.

MR. CHATTERTON:

No. So he says "the contract is terminated". Now ALPETCO says "the hell it is, buddy, I'll see you in the courthouse". Is that a fair scenario.

MR. ROGERS:

I don't understand where we're going with the analogy.

MR. CHATTERTON:

I'm saying that the state can't terminate the contract. I'm asking you how can the state terminate the contract.

MR. BERRY:

Show him where it can terminate it.

MR. ROGERS:

It just says that at the beginning of 10.2, this agreement shall terminate upon the failure of buyer to take each one of those. There is no action required on the part of the state. The contract expires. The state stops delivering the oil. You guys have got the oil. All you do is cut it off and (indisc.).

MR. CHATTERTON:

Then you go to the courthouse and sue us for breach of contract.

UNIDENTIFIED SPEAKER:

On what grounds?

MR. ROGERS:

On the grounds of economic loss. There is no right of action in any court of law. I know the Alaska laws are very similar to all the laws of the other states and there can be plenty of injury but unless there's a wrong, there's no (indisc.) And unless the state had done something wrong or has broken its contract, we have no remedy. Furthermore, I hate to go out on extended examples like this when that's playing economic Russian roulette and our lenders are not going to want to see that.

MR. CHATTERTON:

They haven't loaned you anything yet, to speak of.

AGO 559325

MR. ROGERS:

600 million dollars for a plant -- (indisc. - simultaneous speech)

MR. CHATTERTON:

(indisc.-simultaneous speech) going to get the plant.

MR. ROGERS:

You've got 600 million dollars in the ground. No one is going -- the contract is long because we have made (indisc.- simultaneous speech)

MR. CHATTERTON:

600 million dollars in the ground and you're making a profit and you don't want to go any further.

MR. ROGERS:

I'm saying that the Russian roulette which your example assumes, would not be a rational business decision. No businessman would risk a 600 million dollar plant with no feed stocks to put in it.

MR. CHATTERTON:

That's my point. I say that you will require if you go to court because of the materiality of breach clause on page 42, that if you will go to court and require the state to continue to deliver, I'd dare say the court is going to support.

MR. ROGERS:

No. The materiality -- the breach in that instance would be on our part and our failure to meet our dollar obligation, the materiality clause accepts all of section 10, if you'll note that, number 1. It's right there in the end of the contract somewhere wasn't it?

MR. CHATTERTON:

It's on page 42 at the bottom of it. My point is very simply that the state is suffering no economic loss --

MR. ROGERS:

I was thinking of the reasonableness of approval.

MR. CHATTERTON:

If the state is suffering no economic loss which it would not be, and under the scenario I gave you it wouldn't have its world scale petrochemical plant, so it would be suffering no economic loss and it would still --

UNIDENTIFIED SPEAKER:

(indisc.) the fine legal line of the contract would still be -- there would be no --

MR. CHATTERTON:

(Indisc. -- simultaneous speech)

MR. ROGERS:

I'm having trouble, frankly, seeing why -- there's a (indisc.) provision at the beginning of 10.2 that says the contract is automatically terminated if you don't spend the next incremental amount of money.

CHAIRMAN MILES:

Mr. Rogers or Mr. Berry.

MR. BERRY:

Could you -- I'm having some difficulty understanding (indisc.) familiar with this type of contract in the construction business but what exactly does commit to expend mean and whether there is any standard for that or any time period to assume to be connected with a commitment to expend a certain sum of money.

MR. ROGERS:

I think the context of the being is a contractual ligatory and enforceable contract which we have entered in an (indisc.) purchase order for that for whatever it is. But many of these components are built over a period of several years and the delivery schedules are not completely within our control and that's what the commitment -- we don't know exactly when we're going to spend it but the binding nature to pay for it is what the commitment is, an obligation to pay for it.

MR. BERRY:

So that it would entail a purchase order or an order for the construction without pinning down in any way the time frame over which the construction would (indisc.).

MR. ROGERS:

Right. The reason we're in all of these dollar things rather than in specifications is that frankly we don't know exactly what the configuration of the plant is and what the time frames will be. Particularly with such a large facility like this, the great variable right now is what the purchaser of the product wants. And we don't know exactly (indisc.) is. There are some

processes presently that no one knows whether they're economical or efficient now if the new union carbide ethylene processes are efficient as everybody says, that a purchaser will want more ethylene because it reduces the cost of producing ethylene by 30%. We could not stipulate that we will have an x or a y or a z by a certain amount of time because we do not indeed know (a) whether that particular type of unit is going in and (b) what point in time during the construction schedule that particular unit will go in. So we found the benchmark in the one common ground and that is spend enough money to be able to insure that something large and something of a petrochemical nature was being built. It's -- under the present thinking, it's impossible to to spend a billion and a half dollars and build just a fuels refinery without going way over the assured source of crude oil. As I think I mentioned before a 150,000 barrels per day refinery would cost less than 700 million dollars. A billion and a half has to go somewhere and that's into petrochemicals.

CHAIRMAN MILES:

Representative Chatterton.

MR. CHATTERTON:

Thank you, Mr. Chairman. Just to continue. Ed, you have 14.3 on page 42, I believe, in front of you.

MR. ROGERS:

Let me explain one thing that's rather technical and was a request of ours. We asked that the termination provisions in Article 10.2, the benchmarks were not called a default or contract breach but that the state merely had a right to terminate our agreement and be covered for any loss. We're obligated, for instance, to continue accepting deliveries of oil and things of that sort so conceptually 10.2 is not covered as a default or a breach of contract. It is merely a grant -- the reason why it's in Article 10 rather than in Article 14 is that it grants a right of seller independent of breach or anything else, the right to terminate the contract. If you don't do this then the contract ends. The one safety valve to that or the extension period stipulated in 10.2 that permits us to seek an amendment to the contract or get an extra little time if something has delayed us.

MR. CHATTERTON:

Okay. Then it is distinctly your belief that the contract says if within 72 months, I think another six months probably, extends for 12 months, within 84 months if you have not expended or committed to spend one and a half billion dollars why we can cut the oil off -- that we can cut your oil off?

MR. ROGERS:

Exactly.

AGO 559328

MR. CHATTERTON:

You would have no recourse against the State?

MR. ROGERS:

Right. I think also, if we assume your example of -- your example does have credibility in the area of the building. It's my understanding that the fuels portion of the facility will be the first and then the higher processing will be built later. In the event that at any point you feel that we are not committed to a petrochemical facility and probably -- I cannot keep us out of the courts, that's the only way to resolve things if everybody's yelling, but I think you have a good action under 4.2 to say you have violated your obligations to build a petrochemical facility. You're just building a fuels refinery and you can see the termination that way. Our great fear, frankly, is that we're pouring so much money into this thing, we're never going to do anything to even imply a breach because with so much money involved I think we're going to do everything we can to exercise caution.

MR. CHATTERTON:

Of course the definitions section of petrochemical facility refers you to the language in 4.2.1.

MR. ROGERS:

Right.

MR. CHATTERTON:

And, you know, if that really says that you -- it has the word petrochemical manufacturing facility in the fourth line of that paragraph. But it sure as heck doesn't define it, does it? Just read that. "Such facility shall include facilities for the manufacture of energy fuels"; that's my 30,000 barrels "aromatics", yeah, it's going to manufacture those because they're going to come off "olefins", it's going to manufacture those, they're going to come off "and petrochemical derivatives"; that's the whole suite of chemicals, it's going to come off. It's not going to be sold as a product. It's going to be dumped into one of these tanker company's ships and sent down south just like it is on any refinery in the State of Alaska now. It hasn't told me a thing that you're going to make any petrochemicals or some of the derivatives.

MR. ROGERS:

The problem that we wrestle with in trying to define anything further in the contract is that we can't define that until we

know that the producer, the purchaser of the product -- we have been doing this thing chicken and egg for many months now. And a purchaser won't talk to us until we've got a supply and hardly anybody else for that matter, so that we in this paragraph did not want to bind ourselves to any particular configuration.

MR. CHATTERTON:

I agree, you did not.

MR. ROGERS:

We hopefully have, and I think, honestly speaking, that if everybody will keep their copies of our presentational material in which there are described a mammoth, world scale heavily petrochemical refinery, that ALPETCO would look pretty silly in court saying well we complied with them. We had a few olefins and petrochemical derivatives being (indisc.) off this fuels refinery here. The judge is going to say well how about this nice two volume blue brochure you submitted to the state. What is this thing that you submitted here. And I think the description of this has to be rounded out with the context of the facts of the contract. I would not like to be -- I'll join the Alaska side on that.

MR. PRATT:

May I ask a question, Mr. Chairman, strictly from a stupidity point of view?

CHAIRMAN MILES:

They are so used to stupid questions, Mr. Pratt.

MR. PRATT:

Is Tesoro and North Pole presently producing olefins and aromatics?

MR. CHATTERTON:

Sure.

MR. PRATT:

They are.

MR. CHATTERTON:

Well hell yes.

MR. PRATT:

Polypropylene, polyethylene?

MR. ROGERS:

Not the polys, I don't believe. I think --

MR. CHATTERTON:

(Indisc.--simultaneous speech) we're having an unsemantical understanding here. As a saleable item, they are not, no. As a saleable product, they are not. But keep in mind that's what crude oil is. Now all they are removing from crude oil let's say Tesoro or a Chevron refinery or North Pole, all they're removing from the crude oil is what are called middle of the barrel products, the stove oil, diesel oil, jet fuels. Now that's being removed. Now everything else, all the olefins and all the aromatics and everything else are also being removed from the barrel but they are being shipped south.

UNIDENTIFIED SPEAKER:

(Indisc.)

MR. CHATTERTON:

Yeah. They are being shipped not as separate items, but as a addition----

MR. ROGERS:

(Indisc.--simultaneous speech) the production of that is just what comes off naturally, rather than what's produced and its' a very small amount in relationship to the fuels produced.

MR. CHATTERTON:

No, actually it's very large, about two thirds. Each barrel that goes through one of these refineries in Alaska, well about a third of a barrel stays in Alaska as products and two thirds is shipped south.

MR. ROGERS:

In what form?

MR. CHATTERTON:

In liquid form.

MR. ROGERS:

They're not aromatics or olefins?

MR. CHATTERTON:

Yes, there's aromatics and olefins.

MR. PRATT:

Are you saying that they're all mixed up together in one barrel?

MR. CHATTERTON:

They are not in into individual products.

MR. ROGERS:

I think that in the context that this language speaks, we're speaking about the production of separated olefins and separated aromatics. It's not -- I think that's what the parties certainly understood and while it's possible in a fuels refinery to draw off certain small amounts of separated -- I don't think the industry considers anything an olefin or an aromatic until it's separated from its generic tie.

MR. CHATTERTON:

I think you're right. I'm paranoid, I admit it. I can't see the language (indisc.--simultaneous speech).

MR. ROGERS:

As John Barbour used to say, I'm not really paranoid, everybody is trying to persecute me.

MR. CHATTERTON:

Thank you, Mr. Chairman.

CHAIRMAN MILES:

In Exhibit B that deals with determining the value, why is it that though some mathematical fluke the figure that comes out the weighted average (indisc.) just happens to be one of the figures that's up there? It just seems unusual that that would be the case?

MR. ROGERS:

Where's this (indisc.)?

CHAIRMAN MILES:

It's (indisc.) B-2.

MR. ROGERS:

By some fluke it's ...

CHAIRMAN MILES:

(Indisc.) same weighted average price that one of the independent producers -- or one of the individual producers. It just seems

strange that it would come out that way.

MR. ROGERS:

Yes, that is a mathematical fluke. This was taken personally from an actual production report and it was not constructed, it was taken -- it may have been adjusted (indisc.--cough) but this whole thing began from (indisc.--cough) and Mr. Boness created a very lengthy mathematical model of the way that the state believes the pricing should be under its leases which incidentally (indisc.) not agree and there are, as you know, four different prices stipulated in the lease; market and posted prices and the two prices stipulated in here. There is no posted price in the field and because of the way the formula works, the vague reference to market price in the lease and it probably means the weighted average of all producers in the field or something like that. It could also mean market price in comparison with totally different crude oils like Saudi Arabian crudes. No one knows exactly what not standard means so we used the two standards here which are what you see in number 9. The actual value of the oil of each producer, the weighted average of all other producers which is put in a lease to (indisc.) the inefficient or how do I say it nicely, penalize the producer who is giving a brother-in-law price to someone for reasons of his own. He still has to (indisc.-cough) price of all the other producers. It's a way of making sure that there are no bargain prices which yield an unfair royalty price to the state.

CHAIRMAN MILES:

Anybody who's concerned with government (Indisc.) Arlon Tussing made his presentation.

MR. ROGERS:

His (indisc.) theory.

CHAIRMAN MILES:

There seems to be some argument between Mr. Honig and Dr. Tussing on exactly how this figure was arrived at.

MR. ROGERS:

It could be because this gets awfully complex. This is an extremely simplified model because you have 29 producers and a lot of those producers are delivering to multiple delivery points, so the actual price needs to be done on a computer. Once you're familiar with the way it works it becomes very simple and all it means is that if you have a, b, c and d, you just take the weighted average and if the guy's actual price is higher than the weighted average of all of the other producers, then he pays his higher price. If the weighted average

of the other producers was higher than his actual delivery price then it's the other. And that's probably the practical way the formula in the leases are going to work out over the long run anyway. But I think -- I was not here for Mr. Tussing's presentation but I was not aware that he -- I thought his main concern was that by taking that $7.03 we could do something with the oil that would disrupt the market and somehow eventually mess up the ultimate state's value utilization. Henry knows more about this than I do, perhaps he could (indisc.--simultaneous speech).

MR. PRATT: -

Mr. Chairman.

CHAIRMAN MILES:

Mr. Pratt.

MR. PRATT:

Just a comment on it. I think our difference of opinion at the time was Arlon just used three figures. This company's spending 12 something, this one 12 something and this one 11.46. He didn't use the 11.46 price to show how with that difference in there you could (indisc.) down the overall price. We were saying you don't end up with the 11.46, it's that simple. You have to weight the average of the highest with each of the producers as individuals and then weight those to end up with the price. So that the differential between what we would be paying in the highest price paid wouldn't be as great as he reflected it on the board. That's what the difference of opinion was, that he was using a vast disparity in terms of the figures that he marked down. He didn't represent them to be accurate, he said let's just use some figures, but if you look at those kinds of differences you begin to see millions of dollars worth of loss. And we're saying that's not the way it will actually work. The differential will be so small between the actual highest paid and what we'll pay that while we're (indisc.) it won't be the kind of loss you're hypothicating.

MR. ROGERS:

My sister has a PhD in math and I think she got all of the genes when she was born and I can't figure out all of the mathematical models that all of these people (indisc.). We've got into the problems and the economic effect of removing this oil and disposing of it in some way in the interim stage and then the second phase of that is when our oil is removed from the market and processed in the petrochemical facility, there's a call for reverse ratchet theory in which it's almost a certainty that by taking the crude oil out of the market we will increase the in-value receipts of the State of Alaska by removing 150,000 barrels from the market on the West

AGO 559334

Coast or Gulf Coast or wherever it's going and stop deliveries from the most inefficient point. And the in-value calculation under this formula will all go up and we'll all be happy and scratching our bellies.

We got lost in all of the variables when we were talking about this during negotiations and the wild price gyrations that Mr. Tussing thought are possible, are improbable because there are so many different things that are happening. The largest thing in our contract now is that when the reverse flow pipeline is put into effect it was going to reduce transportation costs from California to the Gulf Coast substantially and you're eliminating a whole lot of (indisc.) gyrations. The markets between the Gulf Coast and the West Coast do fluctuate and the earliest in our delivery will begin in 25 months and it's difficult to -- I think Tussing assumed the absolute worst that could possibly happen and that is so improbable that it's not a concern to us. It'll certainly not be motivating our debate.

CHAIRMAN MILES:

The only reason I was concerned was there did seem to be differences of opinion on exactly how this was to be calculated. We had two supposed completely independent figures, not identical.

MR. ROGERS:

That is a mathematical mistatement, not a mistatement, actually in the way his prices are arrived at, I can assure you there's no difference between the Department of Natural Resources and ALPETCO and the Department of Revenue who's been privy to all of our discussions. I think it's a very fair price (indisc.).

CHAIRMAN MILES:

Mr. Rogers, three or four days before the Commissioner indicated that he was going to recommend a contract, the ALPETCO contract. He came out and said nobody was matching what he was (indisc.). Could you (indisc.).

MR. ROGERS:

Commissioner LeResche is a very good administrator. He wrote -- probably the best way to do it would be to look at his last letter to us. That statement was preparatory to sending a letter to each of the bidders saying please change this or your contract was unacceptable and put us in the unenviable position of either accepting or possibly losing the contract to another bidder. We adopted with a few exceptions all the requirements.

CHAIRMAN MILES:

And what were they?

MR. ROGERS:

I would have to go back and and dig in my notes. If you want to give me a few minutes I can probably leaf through here and tell you what some of the problems were. The numbers were not final until the last few days. We had asked at all times for 90% (indisc.) 90% under 2.3 and 90% under 2.4. And as you can see the results 85 + potential 5% more in Prudhoe, 90% in 2.3 and 70% in 2.4. The Commissioner's concern there was that he have in reserve adequate quantities to serve future in-state needs. Those in-state needs theoretically are not necessary to be spoken to in 2.3. By definition you're selling something that's excess to the state's needs so that was the area where we were allowed to continue our 90%. The point of delivery in our minds was open until the very last, the part of the state for delivery. We always wanted Valdez as the delivery point and that was simply unacceptable to the state. The state indicated that they did not want to be in the oil business (indisc.). The charitable foundation -- I would say there were small changes that were necessary which I cannot remember at this point. The others were potentially (indisc.--poor quality of tape). (Indisc.) just making clear exactly what was to be paid into the charitable foundation, the definition of the net after tax profits. The requirement also was placed in 4.4 and one other place that prevented us from doing what the state is concerned other parties have done with them and that is to enter brother-in-law transactions at unfair prices so we put in a paragraph requiring any transaction between affiliates to be on fair terms. The storage of oil section was nullified and watered down substantially and I don't know if it's wise to speak to it because there's a question legally as to what rights, if any, the state has to storage. The state was very careful to protect itself to insure that they were not warranting in any manner that there was any storage rights. It is unclear what those storage rights were and those were some ending changes.

There were a number of changes to the measurement section but I don't think you need to be concerned with them. They eliminated a lot of standard language that did not apply because fuel practices at Prudhoe were somewhat different than standard fuel practices. A lot of the last minute changes were pulled in some final comments from a number of agencies that had expressed concerns and had read a draft. We were rushing to the end of the negotiations so many of the changes were not -- did not reflect hard bargaining or anything but some last minute comments of other agencies. The price section was pretty much in order before the end. We were agreeable to it. There were some changes to 8.2 that made clear that any costs whatsoever incurred by the state by taking in-value -- by taking in-kind rather than in-value were our problem.

UNIDENTIFIED SPEAKER:

(Indisc.)

MR. ROGERS:

Yes. 8.2 was revised in every draft and our concern was, of course, in negotiations getting a defined price of some sort to know what we would be walking into in terms of cost. The state, for obvious reasons, did not want to guarantee that a certain price would pertain and that certain costs would or would not be incurred, otherwise they would be unable to represent to everyone that the in-value price would be realized. And in the last stage of the negotiations we yielded on the point and have agreed to pick up any other costs.

MR. CHATTERTON:

(Indisc.)

MR. ROGERS:

The payments and billing section has been in pretty good shape. There were changes to 9.5 which is adjustment to billings to reflect -- we will be buying the oil and paying for it on a month to month basis and there will be some changes necessitated by possible clerical errors, mistaken reports of the producers on which the billings would be rendered, the outcome of the litigation and the state's litigation with the producers and all those were attempted to be taken care of in Article 9.5. I think they have now been done successfully except for the litigation with the producers. We're trying to cut off everything at an early period and stipulate a reasonable period of time.

CHAIRMAN MILES:

Could you go through these a little bit faster.

MR. ROGERS:

Oh sure.

CHAIRMAN MILES:

Because I want to establish what concessions did the state give ALPETCO and time-- (indisc. -- simultaneous speech)

MR. ROGERS:

I think I can answer that pretty simply. The state could not give any concessions. We were not permitted the opportunity at the very end. We were told either put those in or perhaps find the contract unacceptable so we yielded on those points except those--

CHAIRMAN MILES:

Before we get into that, were we finished with concessions the state controvened in these sessions?

MR. ROGERS:

No.

CHAIRMAN MILES:

Can you finish those.

MR. ROGERS:

I think I've covered most of them. The next big number of changes were a number of technical changes to Article 12.1 that related to the security interest. And most of those changes were initiated by New York counsel.

MR. CHATTERTON:

The State's New York counsel.

MR. ROGERS:

The State's New York counsel. There was a rather wholesale substitution of language done at the very last draft. I believe the second last draft the state had us put in new 25.1, the local hire provisions, were substituted for some other ones that had been contained in a number of drafts. And in the second last -- Exhibit D, the supplemental environmental standards, were added during the last period of time. The referendum was the very final change that was put in and that's in page 51 before I forget it. Our second last draft it was on a Mag Card and it got run through without the clause and some wrong drafts were circulated and I was accused of all sorts of wrong doings.

CHAIRMAN MILES:

You're saying that the state made no concessions at all --

MR. ROGERS:

It's my memory. If you want to call it a concession, we mutually worked out the language on page 4 and 5 with the Prudhoe oil and tried to dovetail the North Pole contract with our contract. The decided reason for reducing us from 90 to 85% was because of the needs of North Pole. They basically said well if they're not taking it, then we, because they've not been taking it under their contract presently. And the answer was yes. And the same as to the provision of the return oil. Let me think

AGO 559338

just a moment. I can review my notes and reply. If I find some more, I will contact your office in the morning and let you know.

CHAIRMAN MILES:

When did the provision for the bottom of tank and the filling of the line get (indisc.)

MR. ROGERS:

During the arguments about delivery point we were simply unable to agree on delivery point and after a while decided to share concerns and our concern about taking at pump station number 1 was number 1, many of the carriers have lien prohibition. That was the reason why Article 12.1 is such a mess because we needed to make provision for passing the oil down the pipeline and giving the state security but not letting the oil get in a position to be rejected by the carriers because they can refuse oil that has a lien on it, even a state lien. The other concern was that we would have a bunch of oil in the pipeline that is not usable to us until we get to Valdez and it was in the nature of a compromise that we agreed to the principle of pump station number 1 if the state would agree to the pipeline fill. That is not going to be a 100% requirement under present tariff requirements. Many of the carriers provide fill for some reason that I don't quite understand and so it's not going to be a requirement that the state provide 100% of what might be required.

CHAIRMAN MILES:

Was this agreed to last week (indisc.-- no mike near speaker)

MR. ROGERS:

I don't believe so. It was agreed to in San Francisco. When was that, November?

UNIDENTIFIED SPEAKER:

December.

MR. ROGERS:

December.

UNIDENTIFIED SPEAKER:

Yes, December.

CHAIRMAN MILES:

Ms. Kallab.

MS. KALLAB:

AGO 559339

(Indisc.--no mike near speaker)

MR. ROGERS:

As it's turned out, originally it was something very valuable to us. As I mentioned, we wanted pretty large storage. .. The more we look at it the more difficult it is to see some tangible clear rights. The storage, if it exists, is probably up in Prudhoe Bay. Nobody knows quite what the language in the lease means and the state, with good reason, insured that it has no exposure in the event no storage rights show up. It will be our job to assess whether there are any rights and whether it's worth pursuing any litigation and if there is any litigation, it would be at our cost. It is not regarded -- at the time of the contract execution it was not regarded as a substantial concession.

MS. KALLAB:

I may have missed something here, possibly. Is the storage right at Prudhoe Bay or is it both at Prudhoe Bay and Valdez? Here it says from the (indisc.) and I don't know what the (indisc.) says.

MR. ROGERS:

Well, the clause in this contract speaks to the storage rights under the lease and the answer to your question is that it's very unclear.

MS. KALLAB:

Oh.'

MR. ROGERS:

The leases themselves say that storage will be provided by the lessees, if necessary. And the rest of it you've got to write your own scenario. And it's suspected that the point of storage is at Prudhoe Bay and no one knows what reasonably necessary is. I'm not sure where this all ends us up except that I don't think the storage rights are that substantial and because of the strong interest of the state in protecting and making sure that they were not making any warranties of storage, I don't think the state thought they had substantial storage rights. We will find out and get a better fix later on whether those storage rights exist though. It was very important at the beginning and it's one of those things that has become less and less important as we have focused on the lack of clarity in the languages and what the leases probably mean.

CHAIRMAN MILES:

If the option to take lower priced oil is exercised by ALPETCO that scenario (indisc.) What happens to the Prudhoe royalty oil? Do you still own that or does the state get it back?

MR. ROGERS:

To the extent we're getting less than 150,000 barrels, we get to keep it, of course. But if in exercising the lower price we go over 150, we have to reduce our Prudhoe take and therefore the state will get either in-value or (indisc.) in-kind, free of any restrictions that portion which it gets back.

CHAIRMAN MILES:

So the state would get that back if you take a -- assuming you get up to 150.

MR. ROGERS:

Right.

CHAIRMAN MILES:

The state would get complete control of the oil back.

MR. ROGERS:

Yes.

CHAIRMAN MILES:

Representative Chatterton, do you have any questions?

MR. CHATTERTON:

I have a couple of unrelated questions. One, there's no question in your mind but what for oil other than delivery to pump station 1, point of delivery as covered under paragraph 3.1 is defined as nothing more than an agreement to agree, is that right?

MR. ROGERS:

Say that again.

MR. CHATTERTON:

Okay, any oil outside of the Prudhoe Bay crude being delivered to you at pump station 1 or the LACT meter, to make up your 150,000 barrels a day (indisc.), I think that 3.1 in effect defines point of delivery for such oil, outside oil, extraneous oil or whatever you want to use, is purely an agreement to agree. (Indisc.--no microphone)

AGO 559341

MR. ROGERS:

No, I can't agree with that because that means that we don't have a contract on that then. I think as to any oil outside the Prudhoe Bay oil, the delivery point will be the point of delivery of the royalty oil to the state. Under its leases that means it's probably at the well head -- that is a point of litigation in the producer's litigation. It may mean at the edge of the lease. But wherever the state's taking it, we will take it from.

MR. CHATTERTON:

(Indisc.)

MR. ROGERS:

3.1 just says where's it's going to be. That's a pretty definable place, I would think. And it refers back -- it's the oil that will be sold under 2.3 and 2.4 which we've discussed.

MR. CHATTERTON:

Well down here -- delivery under this article 3.1 be made at such other points of delivery as may be mutually agreed between buyer and sellers.

MR. ROGERS:

Right, if we agree on it -- another place that the state took delivery.

MR. CHATTERTON:

(Indisc.)

MR. ROGERS:

Absent that agreement, we would pick it up wherever the state picks it's oil.

MR. CHATTERTON:

Okay, one other thing, completely unrelated. Do you happen to know whether Barbour Oil or any of Alaska Interstate's, the Alaska Interstate members of the complex, have any subsidies under the entitlements program?

MR. ROGERS:

I would assume that the Pride Refining Company, which is operated by Seatrain Lines, being a domestic refinery, has some. It's between a 35 and 40,000 barrel a day refinery so I'm pretty sure its got some. Alaska Interstate does not have any to my knowledge.

MR. CHATTERTON:

It does not?

MR. ROGERS:

No.

MR. CHATTERTON:

Thank you. Thank you, Mr. Chairman. Pride Refinery's in Abilene, Texas, Mr. Chairman.

MR. ROGERS:

I'll check and make sure of that.

CHAIRMAN MILES:

Ms. Kallab.

MS. KALLAB:

I'd like to (indisc.) -- question of exportation (indisc.--no microphone)

MR. ROGERS:

Mr. Van Ness's (ph) firm, which has been working on the DOE stuff has advised us on that and given us a pretty clear set of guidelines. If you look at the Energy Reporter, it doesn't take long. There's a definition of products that you can and cannot export. Basically all fuels are prohibited and fuels -- this is -- I'm really not a petrochemical expert so I may be using some wrong terms in the categories but I believe Naptha and Benzine are classified as fuels and are prohibited but the downstream products are perfectly okay for export.

MS. KALLAB:

Would this be available to us? (Indisc.)

MR. ROGERS:

Surely, I have it -- Commissioner LeResche has it. I have a copy at my office that I'll be glad to send you. There's a CCH export Control Reporter that I'm sure is in the Law Library here and it would be in there. If you take someone like Bob Maynard (ph) and sit him down for an hour, he could get it. I will send copies of it to you and if it confuses you, I'll send an expert in and have Mr. Van Ness explain it to you.

MS. KALLAB:

I have a couple more questions. Has the contract physically been signed between LeResche and (indisc.)

MR. ROGERS:

Yes.

MS. KALLAB:

There are physically signed copies?

MR. ROGERS:

Yes, I could not tell you where they are right now.

MS. KALLAB:

Then under 4.2, or 2.4 rather, what do you consider to be the date of execution (indisc.). What is your definition of that? On the top of page 9, yeah, line 6 or 7, what is --.

MR. ROGERS:

That I must lay at my own door step. That is my language and it was, a concern that there might be commitments made between the date of signing and the effective date of the contract. Of course, if the contract is not approved, it all becomes moot, but if it does, it automatically kicks in the -- as it turns out it's a moot concern. I was concerned that there might be a commitment. As it turns out there is none committed so that there's really nothing to worry about and it was a needless provision, I believe.

MS. KALLAB:

Okay. If you were to re-draft this contract you would (indisc.)

MR. ROGERS:

Yes, Um humh.

MS. KALLAB:

Oh, under section 5.5, subsection 2, (indisc.) the state had to provide ALPETCO with the most recent anticipated production schedule (indisc.) Since you're only getting oil or contracted for royalty oil, what's the interest in the gas?

MR. ROGERS:

I really honestly can't tell you. I can tell you where that provision came from. The language was different there and we were advised that the language was vague and we asked someone from Brown & Root to tell us what they wanted. At the time there was some -- I just honestly -- this language came wholesale from Brown and Root and

no one has questioned why we're interested in gas and I can't honestly tell you.

MR. CHATTERTON:

(Indisc. -- something about making a guess) They are in the construction business. This is public information.

MR. ROGERS:

That's what it was. Kathy just reminded me that at the time we were getting this information together there was a lot of controversy about the effect of gas production, particularly at Prudhoe Bay, on oil production. And we sort of drug a dragnet to get as much information as we could. There were some alarming newspaper reports anyway that indicated that the more gas you pulled out, the less oil you pulled out and that there were going to be some disasterous reports and this was about the time that that language showed up. I think that was the reason for that.

MS. KALLAB:

You're speaking of the Doscher (ph) report?

MR. ROGERS:

Excuse me.

MS. KALLAB:

Was that the Doscher Doring (ph) report?

MR. ROGERS:

I don't know.

MS. KALLAB:

(Indisc.)

MR. ROGERS:

I don't know the name of it, it must have been.

MR. CHATTERTON:

It strikes me that it probably was but I can't totally recall, myself.

CHAIRMAN MILES:

Could you explain the supplier-purchaser section for us?

MR. ROGERS:

(Laughter) That came from our Department of Energy wizards in Washington.

CHAIRMAN MILES:

Were they really (indisc.--laughter).

MR. ROGERS:

Compared to them I'm a perfect example of clarity.

CHAIRMAN MILES:

Just kind of translate that --

MR. ROGERS:

Let me translate it through and give you my explanation of what I think it means. The first sentence is a broad one to cover anything we've forgotten that both the state and we will take any action that is necessary to try to get the transactions accomplished. Then begins the language that is necessary to insure compliance with FEA Rules, DOE Rules. In the event that this agreement is terminated, seller and buyer, that's mainly buyer -- we have to agree that we don't mind the state terminating because there is a right on the part of the supplier to insist on a continuation of the supplier-purchaser relationship. Under the rulings that the state has received and ALPETCO has received though, the DOE has affirmed the use of an in-advance waiver of rights to continue the supply relationship. Am I talking in circles yet?

CHAIRMAN MILES:

(Indiscernible--laughter)

MR. ROGERS:

There is a right under the energy regulations -- it's designed to keep in place all of the energy distribution channels that existed in 1973. For that reason, if you have a supply contract the supplier has the right to insist on a continuation of the supply relationship, notwithstanding it's contractual agreement. The state, of course, does not want to enter the contract and be unable to terminate the contract because of Department of Energy insistence. Our standing up and saying, hey, we realize under the contract you've got a right to terminate us, but under

present federal law, you have to continue the supply relationship. So the Department of Energy has said it's perfectly okay number 1 because the Alaska production came on-stream after this frozen period in 1973 and because it's a different market and because we're dealing with the state, which is a different character of party, to waive in advance any rights for us to insist on a continuation of the supply relationship.

CHAIRMAN MILES:

Then does that -- are you saying that if the feds would mandate an interruption, you guys are out-to-lunch or the state's out-to-lunch?

MR. ROGERS:

It says that the state terminates our contract if we fail to meet our 18 month criteria. It means that we cannot stand up and and say, hey, the Department of Energy says you have to continue our oil. Well that's not a theoretical possibility because we can't get our oil until after that. Say we're at the -- this example we used before, we're at the hundred million dollar level going on to 600 million dollar level and the contract was terminated, we cannot cite as a reason to prevent the termination of deliveries, these Department of Energy guidelines. They just don't apply to us. And this language is the language that the Department of Energy says is necessary to give an advance waiver or an advance release to the state. We give you, in order to give up any rights, we have to insist on that. Then to make it even more complicated, if we were selling the oil downstream to some other purchasers, as long as it's crude oil every purchaser and sub-purchaser down the line has the right to insist on a continuation of that supply relationship, so the additional language is designed to require us to pass those same obligations on.

CHAIRMAN MILES:

I'd have to stay up all night to (indisc.)

MR. ROGERS:

I'd disclaim any responsibility for (indisc.-laughter). The first part assumes any general allocation program. The second sentence cites -- says the same thing over again but cites the present program. In order that if there's a -- I'm talking about in 26.6 we have a general sentence and then in the first sentence it talks about any mandatory crude oil allocation program. The next sentence is specifically -- we're talking here and it says the same thing over again about the present federal mandatory petroleum allocation regulations. And then the next sentence is what I talked about --

these downstream purchasers. And that's in any subsequent contracts we'll get the same agreement. The reason it's so confusing is the repetitiveness of the language, I think. Then the next sentence --

MR. CHATTERTON:

You cascade it down one more layer.

MR. ROGERS:

Yeah. It's cascaded down -- that's a very good description. Then we go from a general -- in that long sentence we're talking in general -- we'll pass on the termination provisions and in that final sentence it says specifically we will have this agreement in the State of Alaska royalty agreement as to any termination. I think after you've read that four or five times you just have to take it on faith that the principle reason it is is to allow a rather free termination of the supplier-purchaser relationship in the Department of Energy relations, without interference of the Department of Energy relations.

MR. CHATTERTON:

That's just your interpretation.

MR. ROGERS:

Yes, and they have been passed on I know by the State of Alaska's DOE counsel in Washington to insure that that's not going to interfere. It has been a constant concern of your people.

MR. CHATTERTON:

Thank you.

CHAIRMAN MILES:

On the Article 12 security clause, I have a couple of questions. What kind of a commitment or what kind of a legally binding document is the letter of credit? You know, I don't understand that insofar as a security measure goes and the second question on that is why doesn't the security apply until the crude gets down to the facility? It doesn't attach while it's in transit, yet it's your oil and so actually although point of delivery is the LACT meter, we're still liable because you're not snapping any security on the thing.

MR. ROGERS:

The letter of credit is merely a letter that will say to the State of Alaska, if these people don't pay then you notify us and we'll fund up to the amount of this letter. It will be from a reputable bank and it's better, in my mind, than the security

interest that you get from keeping the oil, because it's cash from a good bank. It's an unconditional promise to pay, it's sort of like a check, a blank -- not a blank check but in essence that's what it is. It's a blank check up to the face amount of the letter of credit. Any time that we fail to pay or that you need to go against the security because of some other reason, that's a breach of the contract, you have the right to notify the issuer of that letter of credit that they should pay the State of Alaska a certain amount of money and it will be drawn down. The specific form of the letter of credit, you'll note, is subject to the approval of the Commissioner and so it's got to be an unconditional letter of credit.

MR. OSTERBACK:

It's like a promissory note.

MR. ROGERS:

Yes, sir. And in fact it's a promissory note from a quite reputable payor that a bank issuing a letter of credit treats that on its books as if it had lent the money and it has to by regulation because it's an obligation to pay that money from that bank's standpoint.

CHAIRMAN MILES:

On the other point then --

MR. ROGERS:

The other point is rather complicated and that's part of the compromise that we reached in the pump station number 1. Three or four of the seven tariffs or eight tariffs, say the carrier has a right to reject the oil if that oil has a lien on it. Under 12.1, there is a lien retained in the oil by the seller. And for very good legal reasons that lien should not be given up until the oil has been paid for. Our problem was that we couldn't accept pump station number 1 if we were accepting oil at a point with a lien on it where a carrier might reject it. We don't want the oil with nothing (indisc.) at pump station number 1. So the contorted result was what you see here. The lien is released as to that oil on which tariffs exist prohibiting a lien and the oil would go down the pipeline and then the lien will re-attach and the complexity of that whole paragraph has been designed around and patched around to insure that at no time can we place a lien on the oil while it's going down the 9 days, down the pipeline. It was a way to satisfy our needs and make sure that we could ship the oil down the pipeline and we did as best we could to insure that the state was fully protected. The result is

AGO 559349

that you will have no lien on that oil -- again it's not all the oil, it's just for these four carriers who have lien prohibitions in their tariffs -- while it goes down the line there will be no lien on it but there's a prohibition against our putting any other liens on it and the lien will be attached once it hits Valdez.

CHAIRMAN MILES:

I wish I knew something about lien laws, I guess I'd understand it, but it seems to me reading 12.1 that we have no security until it gets to Valdez and then we can't slap a lien on the products if we have to after because it says no liens will attach to any oil or products produced therefrom, so we don't have -- will you run that through again.

MR. ROGERS:

Yeah --

CHAIRMAN MILES:

(Indisc.--simultaneous speech) gets to the facility, the facility processes it and then we can't slap a lien on it once it goes out.

MR. ROGERS:

Yes, you can. We can't. We can't put any other lien on it. The lien of the seller automatically re-attaches at Valdez. All the oil coming out of the TAPS line will have a seller's lien on it 100%.

CHAIRMAN MILES:

Where does it say that?

MR. ROGERS:

Well at the beginning of 12.1 it says all oil will have a security interest on it from the point of delivery. Then it says notwithstanding the provisions of the above which say the oil lien will attach at pump station number 1, seller agrees that the security interest shall not attach at the time of delivery but instead it will attach when it arrives at Valdez. As to any oil shipped, not all of the oil, but just to any oil shipped under the tariff pertaining to the TAPS, which contains a prohibition against -- that's the whole basic problem. The tariff says if I tender oil that has a lien on it, the carrier can say, we don't want it.

Some of those carriers are also other producers that have oil that they'd like to ship. We don't want to be in a position where they can reject our oil. And that was one of our biggest arguments for accepting the delivery at Valdez and not at pump station number 1.

CHAIRMAN MILES:

I don't think I (indisc.) Let's go on.

MR. ROGERS:

Let me summarize perhaps for you -- where you end up. The state will always have a lien on all of the oil, all of the crude oil, until it's paid for except in one excepted instance and that's as to those -- the pipeline is owned by a number of people in undivided interests, so you've got more than one tariff. If you have a bunch of tariffs and three or four of those say you can't ship any oil down our line if it has another persons lien on it because that might interfere with our own carrier lien. So we have a right to reject that oil. One tariff says it prohibits any oil that goes in the pipeline that has a lien on it. So we just provided that instead of the lien attaching at pump station number 1 at the top, as to those four, the lien will not attach here but will attach at the bottom of the line. And it also says ALPETCO, you can't put any lien on that oil while it's going down the line or grant a lien on it to any other third party without our permission.

CHAIRMAN MILES:

Then doesn't it further say --

MR. ROGERS:

Yeah, just to that portion of the oil.

CHAIRMAN MILES:

What happens after it goes out?

MR. ROGERS:

The lien re-attaches as it goes off and the lien continues at that point as long as it is not paid for, and to the products that are produced from any, and any accounts receivable that are created by the sale of it.

UNIDENTIFIED PERSON:

(Indisc.)

CHAIRMAN MILES:

So then, where am I, I'm at page 37 about the 6th or 7th line, and the language says no lien shall attach to any oil or products produced therefrom.

MR. ROGERS:

Okay, now that is another exception. We have the right to say over in that storage barrel is a $100,000 worth of crude oil. Here's $100,000, release your lien on that oil and the state is obligated to do so. The state doesn't care because it would rather have the cash payment then it would the crude oil.

CHAIRMAN MILES:

It certainly doesn't seem to say that to me but I won't belabor the point.

MR. ROGERS:

If it makes you feel any better, both of the lawyers working on it will be suprised if this doesn't fox even the best commercial banker. The whole paragraph 12.1 is highly complicated. It has been revised and had the insertion of about 10 lines into it and it is one of the most difficult paragraphs to understand. We have run it over enough that it does what the state and ALPETCO want it to do but it is not easy to understand.

CHAIRMAN MILES:

Thank you. Any questions?

MR. ROGERS:

Do you have a question for me?

MR. PRATT:

I'm worried about Mr. Miles' last question, are you of the opinion that somehow we get the oil into the refinery or the petrochemical complex and thereafter you have no lien on anything?

CHAIRMAN MILES:

Yes, yes, that's my concern and I have to perhaps have another lawyer translate (indisc.)

MR. ROGERS:

It'll take a translation. There are only two instances in which a lien will not exist. From pump station number 1 down to the full

point of payor. Those two instances are this weird situations along the pipeline as to those carriers that have a lien prohibition. And number 2, as to any time that one of the banks -- the specific reason for the creation of little "ii" in the middle of page 37, was at the instance of our lender. He said he wanted the ability to lend us say 100 million dollars and get some security. And if he was lending a 100 million dollars on a hundred million dollars of our accounts receivable, he wanted to have those accounts receivable available for security for himself. So this just provides that it's just a switch and the state ends up with money rather than security which is good for the state. We have the right to have our bank come in and buy $100,000 worth of receivables by paying the state $100,000 in cash.

MR. PRATT:

You have a lien or a security interest on the accounts receivable of the petrochemical complex unless the bank comes in and says, here, here's a 100 grand, now we want that security interest. In which case your security interest on that 100 grand is gone because you've been paid off.

CHAIRMAN MILES:

I just don't read it that way but --

MR. ROGERS:

Perhaps you're forgetting the general --

CHAIRMAN MILES:

I'm not arguing the point.

MR. ROGERS:

Yes, I understand it so go back to the general -- the only way to keep your mind straight as you go through all the exceptions is to keep in mind the general provision at the very beginning which provides for a blanket lien -- blanket security interest to the state on everything. The crude oil, the products, the accounts receivable and the proceeds and then it says well, notwithstanding that, here are two exceptions. And it's the exceptions that are so horribly complex that they've become almost unworkable --

CHAIRMAN MILES:

It's certainly unreadable.

MR. ROGERS:

I plead guilty on that. I can't blame that on some special counsel either.

CHAIRMAN MILES:

Ms. Kallab.

MS. KALLAB:

(Indisc.) Have you made arrangements to correct some non-substantive mistakes that are in the contract? I just wondered if you had made arrangements with the administration?

MR. ROGERS:

Yes, I believe we have.

MS. KALLAB:

Will we be getting corrected copies of the contract then, because they obviously will have to be executed and signed by you as chief counsel?

MR. ROGERS:

Commissioner LeResche will be back in town tomorrow morning and that was one of the questions and reasons I came up here and probably the best thing to do is when the last unexpurgated final, final version is done, we can circulate it with some notation, perhaps a gold star on it, that will indicate that it's the last copy. We were all very rushed and very exhausted when we got to that point and I'm embarrassed that there were so many --

MS. KALLAB:

It's a minor point, but I just wanted to know.

MR. ROGERS:

If you will let me know after we're done, what it is, I'll make sure that it was one of the corrected things.

CHAIRMAN MILES:

Are there further questions? I have a few but it's 9:30 and we've been working hard enough the last 10 days. Thank you very much. We certainly do appreciate your time.

MR. ROGERS:

I'll be here tomorrow if any of you have some more concerns or if you'd like to go over your questions tomorrow, I'd be glad to stop by your office and answer any of your concerns.
You just get in touch with Henry. I'm available to come back up or talk to you by telephone if you run into anything after I leave town too.

*****

SCOMM

#14:8

POUCH V
JUNEAU, ALASKA 99811
OFFICIAL BUSINESS

Alaska State Legislature

TRANSCRIPT OF TESTIMONY OF

ALPETCO

March 13, 1978

BEFORE THE SPECIAL COMMITTEE ON ROYALTY OIL AND GAS

Committee:

Senators:	Representatives:
Chairman Mike Colletta	Chairman Bill Miles
Pat Rodey	Charley Parr
Bill Sumner	Chat Chatterton
John Sackett	Joe McKinnon
Kay Poland	Al Osterback

CHAIRMAN: The Senate Panel of the Special Committee that was appointed for review and evaluation of the Governor's Resolution dealing with the sale of the State's royalty oil. The other members of the committee to my immediate right, Senator Kay Poland, Senator Bill Sumner, Senator John Sackett and Senator Pat Rodey. The House likewise constituted a committee and that's chaired by Representative Bill Miles who will introduce his own people. It's at least the intent of the Senate Panel for these first two days of hearings that they're nothing more than informational hearings to acquaint us with what has transpired by the successful, or tentative successfully award winner, and the State's position as to why that specific company or group of companies was selected. The Senate side most definitely comes in with a little bit of a disadvantage insofar as that Representative Miles' committee has had activity in the interim in this area so an apology before (cough-indisc) if meetings do not seem to generate the type of enthusiasm as some might hope. Bear with us, it's only the first two we're going to become acquainted with what has transpired. With that Representative Bill Miles can introduce his people.

CHAIRMAN BILL MILES:

Thank you Senator Colletta. I'm Bill Miles and to your right is Senator, or Representative Charley Parr and Representative Chat Chatterton. I certainly want to concur with the opening comments made by Senator Colletta as I think as our intent we have, at least I have spent a good deal of time working

with the contracts to listen to your presentation gentlemen, ladies and gentlemen,from ALPETCO, and then we would like to ask some questions at this time but certainly would like you to take the full amount of time for whatever presentation you have prepared. Because of the time constraints that may force us to back up possibly tomorrow, we could have some of you gentlemen back to answer additional questions that may be raised. The House plans to continue its hearings on the royalty oil contract Wednesday and Thursday evenings, I think everybody's (indisc). There's plenty of agendas floating around, if you haven't had one I'll see that you get one. And if necessary, on Saturday. We're intending to raise a number of questions so that we can get as much information as possible. The Governor's urged us to act expeditiously on the contract and we're going to attempt to comply because we asked him first to act expeditiously and hence, if there are some questions that can't be answered we will try to put them in writing beginning of next week in an attempt they can be answered within 7-10 days in writing. And with that unless you have additional opening comments Senator, we will turn it over to the representatives from ALPETCO. If you will please introduce yourself and your representatives and we'll begin.

MR. CHARLES HONIG:

I'm Charles Honig, Chairman of Alaska Petrochemical Company and I will preside during our presentation and I think it would be more appropriate Mr. Chairman if we introduce the people as they participate in the presentation, if that's agreeable.

CHAIRMAN: Your Pleasure.

MR. CHARLES HONIG:

Mr. Chairman and Committee Members, no business endeavor is stronger than or better than the people associated with it. From its beginning ALPETCO has associated world-recognized specialists and experts in each aspect of our proposal. These people are dedicated and will continue to work with us as we go forward. They have been with us in most parts of your state and met with the Royalty Board at many locations. We're here to answer any questions on any aspect of this project and if we cannot answer them as Chairman Miles suggested, we will get the answer as soon as possible. We've agreed to spend our time and effort and money to fulfill this contract because it will be a profitable business venture and we're interested in profits. The State of Alaska will incur no risk nor lose any money in the process. When we succeed, your gain will be substantial and it will be permanent. I'd like to just project some slides if I may to illustrate what we would like to talk about today. We'd like to talk about the ownership of our company, the benefits to the State of Alaska, the viability of the project, and then summarize.

The ownership of Alaska Petrochemical and it's better if we start at the bottom of the chart and go up, as you can see there are three stockholders of ALPETCO: Alaska Consolidated Shipping, Barbour Oil and Alaska Interstate. Alaska Consolidated Shipping owns 20%, Barbour Oil Company, which is a privately-held family company, owns 20%, and Alaska Interstate which is a listed company, owns 60%. Alaska Consolidated Shipping is made up of seven stockholders. The first six listed are, Alaska Native Regional Corporations, which each own 8-1/2% of Alaska Consolidated Shipping. Collectively they own control of that company. Forty-nine percent of ACS, as we call it, is owned by Seatrain Lines, Inc. (ph), also a New York stock exchange listed company engaged in the function shown on the chart. Barbour Oil Company provided the leader of this project in its early phases and whose untimely death we all regretted, because he was a real driver of the project and that was John Barbour. And in honor of John's efforts, we would like to dedicate and name this refinery the Barbour Refinery. Alaska Interstate is an Alaska Corporation, has always been an Alaska Corporation, and consists primarily of the gas transmission and distribution company in Anchorage and Kenai because it was formed right after Alaska became a state in 1959. We're engaged also in exploration production of liquefaction of natural gas in Indonesia which is currently being exported,liquefied and exported to Japan. We're engaged in exploration and production of oil and gas in the U.S. We have an engineering and construction company in the gas processing facilities area which has been in business since 1946, and we're also engaged in pollution control, sulphur recovery processes and manufacturing. So those are the owners of Alaska Petrochemical, the only owners.

Let's talk a moment about benefits to the State of Alaska. We'd like to discuss those listed here. No risk. No subsidy. Additional employment. Additional taxes. The Alaska endowment trust. Shipping capability. Specialized training. Local hire. And controlled industrial development.

First the no risk, no subsidy. Our contract provides no subsidy to ALPETCO. There are no price concessions. We included in our capital requirements all of what are called the off-site facilities, such as ports, docks, utilities. We agreed that we would take no interim crude, no crude during the time the refinery is being put together unless and until we have obtained a commitment for the permanent financing. And once we've obtained that then the contract permits us to take crude on the interim basis, because once the commitment is obtained then everyone can be assured the project is going forward. We obtained from the Department of Energy a favorable opinion which protects the State of Alaska, if we do take crude on an interim basis, and merely provides that an exception in effect so that Alaska can take back the crude even if we have purchased some in the interim. Probably the most important

AGO 559357

no risk area that is provided in the contract is what we call performance benchmarks. And those benchmarks provide that the contract may be canceled by the state if ALPETCO fails to obtain each benchmark in the contract and here is a summary of those. During the first six months after ratification of the contract we must give monthly progress reports to the state, thereafter, quarterly reports. Six months from the time the contract is effective, we must have invested at least 2 million dollars. We must have informed the state of our site selection, and we must have begun the optimization design of the Petrochemical facility. Within 12 months we must have invested at least 3 million dollars. The 18 months time period or benchmark is probably the most important, most subsidy of all, it not only requires that we must have committed at least 10 million dollars but more significantly it requires that we must have contracts for the sale of at least 70% of the products the plant would make and we must have obtained financing commitments for at least 1.5 billion dollars, both permanent and interim construction commitments. It provides we must have completed our BIA and we must have filed for permits and finalize plant design. So that's why I said earlier if we make the 18 month benchmark which involves getting financing commitments, then the project is assured of going forward. Then we have additional benchmarks at 24 months on up to 72 months and except for the 30 month one which says we must commence construction by then, the others relate to money and indicate the minimum amount we must have committed to spend by those times, the last one being 72 months we must have committed to invest at least 1.5 billion dollars. So those are the benchmarks for performance provided in the contract. There are provisions for some extensions of time by the state up to, I believe, a maximum of 6 months, pertaining to some of those requirements.

The other major contract items, our economics, our planning, our financing, are based on using 150,000 barrels of crude oil per day. We will purchase that royalty -- that as royalty crude up to that amount of 150,000 barrels per day. It will come first from and then maybe all from up to 85% of Prudhoe Royalty Oil. The state wanted to retain initially 10% and later 15% because of North Pole Refinery of the Prudhoe Royalty Oil and would sell us no more than 85%, because that's less than 100 and because we are dedicating about 2.5 billion dollars to a on-the-ground facility in Alaska. It is essential that we have the 150,000 barrels a day as a feed stock. So in the event that we are not receiving at least 145,000 barrels a day, for as long as a 2-month consecutive period, we may then ask the state to sell us royalty crude from locations other than Prudhoe Bay, but only if we need it to make up that short fall, and then only up to but not to exceed, 70% of such royalty crude. The state insisted on reserving and keeping 30% of that royalty crude which we would not have a right to ask for. So that is simply make-up oil and it is available only to bring us back up to the 150,000 barrel a day limit.

The contract also provides that we will pay the same in-value price that the state would receive had it not sold the oil to us. In addition to that, should the state incur any expenses in connection with making a sale to us in kind, we have agreed to pay those additional costs.

The next item is--requires a public referendum in the event that we request any reduction in price that we would pay, anything, any request for price below the in-value would have to be voted on--would have to not only be acted on by the Legislature but would have to require a public referendum to approve any price concession. We agreed to the point of delivery after long negotiation and we agreed that it would be Pump Station No. 1 so that the State of Alaska does not become a shipper, which it did not want to do. We agreed that we would provide up to 30,000 barrels a day of fuels for in-state use, Arctic fuels, other fuels for use in Alaska. Environmentally, we agreed to comply with Federal and State rules and regulations including all supplemental state standards whether or not those supplemental standards are required by law. We agreed we would observe them even if some of those being contested currently are not upheld. Those are the principle major contract terms.

I'd like to ask Willard Hanzlik who's the Vice-President with ALPETCO and Alaska Interstate if he would talk about additional employment and additional taxes among the benefits, Willard.

MR. WILLARD HANZLIK:

The next item on our list of benefits to the state is additional employment. We believe it is one of the most important contributions that this project can bring to the State of Alaska for employment in this industry. Refining and petrochemical industry represents permanent employment, it is non-seasonal, it is not (indisc), it is permanent, and it creates because of the diversity of the different jobs available in the manufacturing process, opportunities for workers to upgrade their skills and to have careers that develop within the industry. On a preliminary planning basis, our experts who are experienced in the organization and operation of facilities such as the one we contemplate, have indicated that these are the types of jobs for the various refinery units listed on the left which will be needed when this project is brought into operation. We have shown minimums and maximums because at this point in time it is literally impossible to determine precisely the number of employees that will be required. However, the range of 1,900 to 2,500 is a fair range and representative of the number of permanent operating and maintenance employees that will be required by a facility such as this. This does not include the support employees which would--the jobs which would be created in the community to support the facility.

To summarize the--those other jobs and total employment picture, during the construction phase which is expected to last approximately 3-1/2 years, a range of between--an average of between 3,500 and 4,000 construction employees will be required by the project. Now those numbers will not land all simultaneously to start the project for of those there will be a build-up and many of the employees which will be in the construction phase of the project will certainly be qualified and have the skills needed to remain and become permanent members of the community and become operating and maintenance employees. To summarize, in the operating phase, the long-term phase of the project, the 1,900 to 2,500 range which I talked about earlier, plus the shipping requirements of the project which would be conducted by our affiliate, Alaska Consolidated Shipping, would require another 250 to 350 jobs and these would be permanent maritime jobs will be discussed later in the presentation. So we are talking about a total of 2,100 to 2,800 permanent jobs. Now this does not include the multiplier of additional jobs which would be needed in the community and those are estimated from 3 to 4 or 5 times so you are talking about a range of 6 to 10 thousand new permanent jobs.

As far as taxes go a project such as this provides a substantial tax base for local and state government because of the considerable amount of capital investment based on a 2.5 billion dollar facility which is what this facility will be ultimately, and based on the projections which we have--are submitting today to the Institute of Social&Economical Research at their request, these are the tax numbers which are--result from the project. On an average year after the project is in operation, talking about a total of 49 million dollars a year. In additional, these are incremental taxes to the State of Alaska, through the property tax structure, through state corporate income tax and through gross receipt tax. Over the total contract period of a 27-year period. The project is for over 1 billion dollars of additional state and local taxes. One way tolook at the comparison between a facility which is designed for the manufacture of petrochemicals versus a facility that is designed for the processing of crude oil into fuels products, is simply to look on a relative-comparison basis and on the same scale is the two bars on the left side represent an average or a typical fuels configured facility (indisc.-cough) which is to be built in Alaska which would cost with all the support structures and utilities and docks and ports, etc. around 750 million and is estimated at about 500 direct permanent employees would be required to operate that facility. The facility which ALPETCO proposes and which would cost 2.5 billion dollars is shown to be substantially greater in terms of the assests invested, therefore the tax base and also the number of employees is substantially greater, several times greater in fact. Mr. Honig.

MR. HONIG: Thank you Willard.

Another benefit to the State of Alaska and provided for in the contract is what we call the Alaska Endowment Trust which

AGO 559360

is a charitable foundation and the purpose of this trust would be to further the social, educational, cultural, environmental conditions in the State of Alaska. It would be funded by contributions made by ALPETCO beginning after the operation had been in--after we'd been in operation for 10 years and it would be equal to 5% of the net after tax profit beginning with the 11th year after start up. We estimate the average contribution would be 10 million dollars per year and for 10 years that would be roughly 100 million dollars. The trust would be administered by an independent board of trustees unaffiliated with ALPETCO appointed by the Governor and confirmed by the Legislature. Another benefit involves shipping and training of Alaskans and I would like to ask Jim Strupp who is the Vice-President of ALPETCO and also the Vice-President of ACS if he will discuss those subjects, Jim.

MR. JIM STRUPP:

Thank you Charles. Alaska Consolidated Shipping will act as ALPETCO's shipping arm, will act as it's shipping arm in several ways. Because of the lead time between ratification of the contract and actual commencement of actual product shipment, we will have enough time to complete new buildings and provide specialized ships for the product movements and this should give us a very, very good optimization from a shipping cost standpoint. Mr. Hanzlik indicated before, we will also provide (indisc) opportunities for Alaskan citizens in the maritime industry, those jobs should approximate 250 to 350 full-time maritime jobs. Alaska Consolidated Shipping has experienced management in ship building, seatrain lines, one of the members of that company is in the ship building business and currently employs 620 employees building tankers as well as other vessels. We have experience in the ship chartering business, manage and charter over 25 vessels at this time and also are experienced in port management, both in the United States and overseas. As you may know, the majority of Alaska Consolidated Shipping is owned by six Alaska Regional Native Corporations, Koniag (ph), Cook Inlet, Aleut Corporation, Bristol Bay, Chulista (ph) and Chugach. And that's backed up by Seatrain Lines, one of the largest shipping companies in the United States.

I'd like to talk now about specialized training for Alaskans. I've kind of broken this down into two phases, that which is already happening and that which is planned. The already happening category, several months ago John Gunderson who is also a director of ALPETCO and a member of the Aleut Corporation, I traveled to Piney Point (ph), Maryland and met with officials of the Harry Lundberg (ph) School Seafarers International Union there. At that time we made arrangements for the beginnings of training programs for Alaskans and currently we have two students from Alaska attending that program, Mr. Ray Klack (ph) who is a member of the Doyon Regional Native Corporation, Mr. Fred Haas (ph) of the Cook Inlet Corporation. They are enrolled in a 3-month basic seaman course and are guaranteed employment upon leaving. The school pays for the total cost of their training, Alaska

Consolidated pays for their transportation to the school. They have indicated to us that they will be more than happy to take in each of their classes several Alaskan citizens as we proceed. We've also made some training program scheduling at our Pride Oil Refinery, which is located--which is owned by Seatrain Lines and located in Abilene, Texas. We felt that it was important to begin schooling of Natives, Alaskan citizens in the basic refinery techniques. We have currently down there in a job rotation program, they've been there for the last 2-1/2 to 3 months, Mr. R. C. Credo Jr. (ph), of the Sealaska Native Corporation, and Mr. Lauren J. Hoight (ph) of Cook Inlet. They'll be asked to come back to Alaska once they complete their training and work with us in additional recruitment programs and development of our planned training programs down the road.

We are also planning extensive training programs for Alaskans in all phases of shipping, and plant operation, plant maintenance. These will be in depth programs conducted here in Alaska and outside depending on the area of expertise needed and these programs will be coordinated with the help of Brown and Root, Chem Systems (ph), Alaska state officials, and labor union officials. With that I would like to turn it back to Charles.

MR. HONIG: Thank you Jim.

Next we'd like to hear from a Senior Vice-President of Brown and Root who's been working with us since the beginning of this project and that's Jimmy Norris from Brown and Root. I might tell you a little about his company that he might be too modest to mention. Most of you probably know that Brown and Root operates world-to-wide, it's one of the largest and most diversified engineering and construction companies in the world. Last year I think it had the largest volume of any U.S. construction company. It's a subsidiary of Hal of Burton (ph) which in 1976 had almost 5 billion dollars in revenues and it has a shareholders equity of approximately 1-1/2 billion dollars. It's experienced in Alaska, it built the production facility for BP on the North Slope, it was a joint venture in two northern segements of the Alyeska Pipeline, it's currently building an industrial complex for the big three industries in Alaska. It's experienced in design engineering construction of refineries, petrochemical facilities and off-site facilities. And in Alaska it works through Alaska Constructors which is a union shop company. Jimmy would you like to talk some about the labor policies we will follow.

MR. JAMES C. NORRIS:

Thank you Charles. Since most of the work that we would do is out in front of us, sometime after hopefully you gentlemen see fit to ratify this contract. We will speak briefly of two areas: labor policies would be the first one. The work that Brown and Root does in Alaska would be done through its subsidiary, Alaska Constructors, with headquarters in Anchorage. Construction would be by Alaskan workers insofar as possible. We would maximize the employment of Alaskans. We would do everything possible to work with the local unions and with the Alaskan government to train Alaskan workers using techniques that are already established. I think Mr. Hanzlik mentioned awhile ago that we're looking at 3,500 to 4,000 average construction employees for a3-1/2 year period. Many of these people can be trained as permanent employees as plant operators and maintenance personnel.

What we want to offer you gentlemen is a clean industry, environmentally safe plant, it's a controlled industrial environment. It's a plant that I have seen over 30 years in Houston, I have watched the growth of the Houston Petrochemical facilities in the Houston area for that length of time. We can say now that in Galveston Bay, which is adjacent to the ship channel, that there is essentially no pollution. It's an area that's good to fishermen, sports fishermen and commercial. It's good to the residential people, it's good to the government, the Manned Space Crafts--Manned Space Craft Center is just nearby. All of these people live together harmoniously and the petrochemical industry is the biggest--one of the biggest employees of people in the Houston area. As a--I guess something that is indicative of the pollution-free environment is that last week I read something published by the State of Texas that 1977 was a record year for one of our delicacies which is the Blue Crab. Some 7 million pounds came right out of Galveston Bay where all of these petrochemical industries are.

Finally, we want to say that this is a highly capital intensive facility. It's a very sophisticated type of industry and it's also very synergistic. What it's going to do, it will attract other petrochemical facilities to this one as well as what you call the downstream plants which manufacture the polyethylene film and the bottles and such things that you would have from plastics. Thank you.

MR. HONIG: Thank you Jim.

One final point on the matter on economic and social aspects, I'd like to read an editorial that appeared in the Anchorage Times on Sunday, February 19, written by Bob Richards who is the Economist and Executive Vice-President of the Alaska Pacific Bank, because it is particularly good in summarizing

what we've been talking about here. It reads as follows:

This week the administration is to deliver to the Legislature its recommendation regarding disposition of the state's royalty oil. Although several experts have questioned the viability of the four proposals before the Royalty Oil and Gas Development Board, it should be noted that the four bidders have been working closely with the state over the past few months to develop plans that make sense for all parties. Now consultants, Bonner and Moore, Associates, Inc., have concluded that at least three of the four contenders are fully qualified.

It seems to me that anyone concerned about the stability and long run health of Alaska's economy should give careful consideration to this marvelous opportunity to expand the vertical integration of Alaska's industrial base. Our willful act of in-state processing of our resources has contributed to chronic, abnormal fluctuations in Alaska's economy. Expanding the manufacturing operations in Alaska will help create a more stable and, therefore, more socially healthy economy in Alaska. Additionally, the ptetrochemical industry brings substantial benefits far beyond those of many other industries. It is highly capital intensive and one of the lowest labor intensive industries of any of our nations basic industries. Therefore, expansion by the petrochemical industry results in very little population impact. The highly automated petrochemical operation requires very few workers and therefore imposes very little additional burden on public services such as schools, hospitals, highways, and so forth. So it is very clear to see that the petrochemical industry relative to other potential industries, imposes a very small social cost.

But what about the other side of the coin? What does this industry do in the way of creating social benefits? Again, in this regard the petrochemical industry is a star performer. Its first social benefit results from its employing highly skilled, well educated, and highly paid employees. These people generally have a high participation rate in community affairs. Their high incomes are taxed commensurately high, and their socioeconomic station in life generally implies fewer social problems in the sense of crime, disease, and the like.

The second social benefit emminates from the petrochemical industry is its contribution to creating a more stable economy. The industry is virtually non-seasonal; as we all know those plants down on the Kenai Peninsula keep producing 365 days out of the year. Alaska's other basic industries fishing, forest products, and tourism, are highly seasonal industries. As a result, typically, employment in Alaska in January is one-fourth below the level of employment in July. Such seasonality creates all sorts of problems. The expansion of the petrochemical industry in Alaska will help considerably to reduce the overall seasonality of employment in our state. Another way in which industry employment varies is it swings from year to year.

AGO 559364

This phenomenon of course, is referred to as the business cycle. Again, Alaska's fishing and forest products industries are highly cyclical industries. Petrochemical industry, on the other hand, experiences considerably less cyclical fluctuation. Therefore, the expansion of the petrochemical industry in Alaska would reduce both the seasonal and cyclical fluctuations in our economy bringing about a considerably more stable employment situation.

The third major social benefit from the petrochemical industry results from the huge taxes and other forms of government revenue generated from this industry. The key factor here is that revenue flowing to both state and local government exceeds by far the additional burden which the industry and its employees place on state and local government. So there are all sorts of excess funds available for the pursuit of a whole array of social objectives, parks, bike paths, better schools, better health care, and on and on and on. This then is what leads me to a very important conclusion which we should keep clearly in mind. It is simply this--because of the huge public revenue generated by the petroleum and petrochemical industries, this type of economic growth is not only compatible with but indeed is conducive to the pursuit of the whole array of our non-economic objectives.

Perhaps I can summarize by acknowledging the general positive relationship between our quality of life objectives and our economic development. Here we have the opportunity to encourage an industry which will bring wages, highly skilled, well-educated people to stable employment and which many fold more than pays its own way in terms of social impact. The social and economic attractiveness of the petrochemical industry is self-evident. So we've discussed these benefits to the State of Alaska -- no risk, no subsidy, additional employment, additional taxes, the Alaskan Endowment Trust, the shipping capability, specialized training, local hire and controlled industrial development. We've talked about ownership. We've talked about benefits to the State of Alaska. We'd like next to talk about the viability of this project.

There we will talk about management, descriptions and scope, marketing and financing. The organization and management doing what we call the development phase, which is where we are right now, is we have a Board of Directors, as shown -- one of the persons on the Board who is here today but will not speak is Terry McCall; many of you know. The Chief Executive Officer we'll hear from later is Gordon Cain and then we have people and companies involved in the technical aspects, the marketing aspects, the legal aspects, shipping, engineering design and construction, finance, legislative affairs, planning, training for local hire and all of these functions have been active since we started working on the ALPETCO project. One of those that has been very helpful to us in both marketing and in technical considerations is Chem Systems, Inc. and we've had two persons work with us there, the President of the Company, Peter Spitz and the Vice-President of the company, Chuck Campbell. Some of you may recall, Chuck Campbell spoke at the Petrochemical seminar in Anchorage late last year. Chem Systems is one of the leading international firms specializing in marketing and technical support of what we are proposing to build. They have offices around the world. They have a staff of 80 full-time professionals. Their clients include most of the world's leading oil and chemical companies. They're experienced in all phases of petrochemical development worldwide, including the United States, western Europe, Japan, and the Middle East. And they're experts on supply and demand and economics in the field of petrochemicals.

The other, most important ingredient to our management, is the person who's going to be the chief executive officer of our efforts. This person is Mr. Gordon Cain. He has over 30 years experience in the petrochemical industry. As a successful, seasoned chief executive officer, he's been responsible for promotion, putting these together, forming the company, staffing and managing petrochemical facilities in the United States. He's had experience with the Japanese. He's put together a petrochemical joint venture company in South America and he's had experience with petrochemicals in Europe. He is currently President and one of the organizers of Petrotex (ph) Chemical Corporation in Houston. Prior to that he was -- he headed up the petrochemical and chemical activities of Continental Oil. He's also currently Chairman and an organizer of Petrocrema (ph) Argentina S.A. in Buenas Aires. I'd like to introduce Mr. Cain to talk to you about what this facility will do and will look like. Gordon.

MR. GORDON CAIN:

Well Gentlemen, here is a rather simple diagram of the units that we will have in the ALPETCO project. The core of this operation will be an oil refinery which is shown on the left side of the screen. And this refinery will be, for all practical purposes, the same as any of the other refineries that have been proposed to be built here. The one difference in it is that we will take the part of the gasoline fraction that is not necessary for the Alaskan market and some part of the heavy fuel and convert that into a petrochemical feed stock.

Now from this point on precisely what we do is not clear because this will be determined by the market and by the nature of the partners that we get. But in general terms this will include an Aromatics plant which will make such compounds as benzine, taulowene (ph), zyolene (ph) and an Olefins (ph) plant that will make compounds like ethylene, propylene, and butadiene. And then there will be downstream plants from both the ethylene plant and the Aromatics plant which would make such things as polyethylene, polypropylene, ethylene lycol which is antifreeze, ethyl alcohol, which is a gin or any other such place; polystyrene, polystyrene fenol -- those are all the number of possibilities that might go into boxes that are labeled one, two, three, four, five over there. Now this will be a large complex and will have a very substantial utility requirement, both for electricity and for steam. And so it will be necessary for us to build a large steam, electric plant and very likely the balance of this is such that we will need more steam than we will electricity so it will have some excess capacity to generate electricity. So it is possible that this plant will have the capacity to sell electricity to any of the nearby utilities or even preferably to have one of the utilities build and operate that part of the plant for us. In addition, if there is coal available at the time we go on stream, this could very easily be a coal fired plant. We think by that time the liquid fuels that we will make will be more expensive than coal and it would probably be more economical for us to operate this with coal firing if the coal is available.

Now going back to the refinery for the minute -- as I said, this refinery is essentially the same as the refinery that has been proposed to be put here by some of the other people and the economics of this refinery part of it, the market that it will serve and so forth, are probably the same as the things that have been proposed before. And in examining the viability of the refinery, we think of course this is a viable project -- and we have support for this in that there were at least two or three other proposers that also wanted to build refineries. Now this was, in spite of the fact that everyone recognizes the cost of construction and operation in Alaska, is greater than the cost of construction and operation elsewhere -- but in spite of the fact, we and other people think that we can overcome this Alaska disadvantage in the refinery. Then if you look downstream from that, the Alaska disadvantage, to the extent there is one, gets to be much less in the downstream projects than it was in the upstream project, in the refinery. And by downstream I mean the Aromatics plant, the Olefins plant and all of the plants that use the olefins. Now the reason for this is that in the refinery you upgrade the crude oil only a relatively small amount per barrel. And as a result, this Alaska disadvantage is a fairly significant proportion of the total cost. On the other hand when you go from these petrochemical feed stocks to things like polyethylene, you upgrade the oil a great deal and this same Alaska disadvantage

is proportionately much less than the downstream part of it than it is in the refinery, so that the addition of these petrochemical facilities to the refinery improve the overall economics of the project. And, of course, in improving overall economics, they increase the probability of success of this. Now this is a big, complicated project and in spite of all of the organizations and facilities that you have seen on the earlier charts, it's going to be a big thing to do and it would tax -- it would be frankly beyond our resources to do by ourselves. And so we fully intend to take into the different parts of this enterprise partners who can bring to it know how in the operations of these particular things, people who are knowledgeable of this and money and agreements to take products. And this is an essential part of our plan and we have many indications of strong interest on the part of these potential partners. And there's a good reason that we should get this sort of interest because the petrochemical business in the United States, and in fact all over the world, is sort of divided into two pieces. About half of it is run by oil companies who have sources of raw material and can break that into petrochemicals with all the advantages of having the raw materials supplied. The other half consist of chemical companies who buy their olefins and aromatics from oil companies and those companies are continually uncomfortable at being in the position of not having a resource of raw material for their operation so it is that kind of company who wants the benefit of the certainty of supply that it would have here in Alaska, that we will look to find partners to help us carry this operation out successfully.

Now the reason that these partners want to get into such enterprises as this is because they need the products that we will put out and Mr. Spitz, who Mr. Honig introduced earlier, will discuss with you the market for the petrochemical products of the kind that we propose to make. Peter.

MR. PETER SPITZ:

Thank you, Gordon. I would like to cover with you now the basis for this project in terms of markets, tentative products and product configurations, economics and feed stocks and also how this project will fit into the overall scheme of things in the world of petrochemical manufacture. This is a very major project, certainly for Alaska and for the U. S. as well, in the sense that it is a large petrochemical facility and one that is needed by the world market at least in terms of quantities for the world market, as you will see.

Now, in starting my presentation, I would like to have you think not so much about the year 1978, but rather the period of 1985 and onwards when many people think we will have quite a different situation in the world of energy, particularly petroleum, scene. The many studies that have been carried out in the world oil situation by such respected organizations as the Department of Energy, M.I.T., the CIA, a number of others, have predicted that regardless of exactly when this will happen, there will be a point in time and probably most likely in the late 80's,

when the OPEC countries will no longer either be able to or will wish to, supply the overall gap in demand for world petroleum. At this time right now, of course, there is a surplus of oil, you might even say a glut of oil and there does not seem to be an oil shortage, but as you extrapolate world energy demands and the the key role that oil fulfills in it, it is not too difficult to predict that by some time in the late 80's, certainly no later than the early 90's, this situation's going to change quite dramatically and by what very recent pronouncements by the Department of Energy and by a number of other groups, have said certainly confirm this.

On this basis the ability for any petrochemical manufacturer to have at his disposal the ability to buy a significant amount of crude oil for a long period of time through the 80's and 90's and beyond, will be extremely important and will be worth a great deal and that really is almost the key of the entire project and why we think this project will certainly be viable.

Now ALPETCO originally started looking at the possibility of either building a refinery or a petrochemical plant because it's not obvious that you should build a petrochemical plant. As you know, some of the other proposers chose to select a refinery as their objective. But in looking at the relative world demand growth for petrochemical versus fuel products, you'll come to the conclusion, as you'll see in this first slide, that petrochemicals grow and are expected to grow at a lot faster rate than fuel products. Now fuel products that are represented by the two lower curves seem to grow with such indicators as population and GNT and in fact, as the U.S. and other parts of the world cut down on their energy consumptions, they grow at a lower rate than these indicators. And furthermore, when you look at the fact or think about the fact that the world must try to get by with less oil as time goes by since it's a perishable limited commodity, it will actually grow at a lower rate because oil will be supplanted by coal and nuclear energy and by other alternative energy sources of a more far out nature in 20 or 30 years. So you see the predicted growth rates for petroleum products is really quite low and will get lower as time goes by and these are not just our figures, but they are recognized figures by people who publish such things including even the major oil companies. And, on the other hand, the petrochemical growth rates which have been high and which will be dropping as a result of the fact that things can't keep growing forever at 8 to 10% per year, are still very high and will in our judgment and that of others such as Stanford Research, Arthur D. Little, etcetera will keep growing at the rate of 5 to 6% over the next 10 to 15 years. So looking at these two things, and recognizing that there is not going to be a need for too many more refineries in the United States, in fact Shell had said at one time that the last U. S. refinery will be built in the 1980's, was quite an interesting statement, about a year and a half ago, anyway lead ALPETCO to conclude that building

a petrochemical facility makes a lot more sense. There will be a need, moreover, for petrochemical feed stocks to be made in refineries so that the refinery that ALPETCO plans to design will fit into the overall scheme of things and in that connection we should note that in all parts of the world, other than the U.S., the major olefins like ethylene and propylene have always been made from petroleum feed stocks such as naptha and gas oil and in the U.S. where gas liquids were used over the first 20 or so years of the petrochemical industry, even there in the last several years, approximately 80 or 90 percent of the new ethylene plants have used petroleum rather than gas liquid feed stocks so that is again the point that was very important in ALPETCO's consideration in planning this facility.

Now I would like to cover some of the markets we are thinking about for the petrochemical products for ALPETCO and in the next slide we see that the U.S. West Coast has a fairly large market for petrochemicals because it consists of 28 million people and as I will note again later, it actually has a very, very limited number of petrochemical facilities and actually no world size ethylene plant. This is almost an anachronism. Other companies have thought of building a plant there but have been unable to do so and we therefore look at the West Coast market as a very logical and very important market for the ALPETCO project since this market is currently supplied through rather long and expensive transportation lines from the U. S. Gulf Coast. The other important market we're thinking about and that's very important to the ALPETCO project is the remainder of the Pacific Basin, which is kind of hard to show on one slide but it includes Japan, Taiwan, the Phillipines, Hong Kong, which has a very high import rate of plastic, plastic resins because it exports a lot of plastic fabricated products, Thailand and Malasia, Indonesia and the Phillipines, and not shown, the West Coast of Latin America and some other countries. And this market is growing rapidly because the population is large. Our company has made a lot of projections and has shown that this market will be able to buy a lot of petrochemicals, and will eventually build their own plants, but not for some time -- in many cases, except for Japan, of course, and will be a very important market for a project in Alaska. Now this market has been supplied, to a large extent, from Japan, but in the last year or two Japan has been losing this export market partly to the U.S., because the facilities in Japan are becoming somewhat antiquated and in many cases because feed stocks in Japan are high and because Japan has other problems that will be discussed by the next speaker. So we're talking about supplying the U. S. West Coast and the Pacific Basin, which are currently being supplied from two areas, mainly the Gulf Coast and Japan, which are in a sort of transitional situation. But now what is happening on the Gulf Coast? The situation in the Gulf Coast is that in the past petrochemical plants were built there because of inexpensive gas liquids and because of a highly abundant petroleum and natural gas feed stocks there. As you, I'm sure, know these gas and petroleum products are now in decline there. Every year production rates go down, particularly for petroleum products and will keep decreasing

AGO 559370

and so the logic of building plants on the Gulf Coast is no longer there except for the existing infrastructure which will obviously continue to be an attraction to some companies who want to locate there. But the feed stock advantage will no longer be there, particularly as crude oil reaches world market levels. Everybody will be using feed stocks of roughly the same price as time goes by. In Japan where, I said before, there are problems with high feed stock prices and plant siting, there will also be difficulties so what we're really seeing now is a kind of a structural reorientation of the industry where petrochemical facilities are not as likely to be built either on the Gulf Coast or in general near existing downstream facilities but rather in areas where crude oil or natural gas or gas liquids are being produced. This immediately brings in mindthe OPEC countries which, as you know, have great ambitions tc build petrochemical plants and are in fact building some plants. The problem with the OPEC countries though is that number 1, the construction costs there are even considerably higher than in Alaska on the basis of having absolutely no infrastructure in the sands of the Middle East. We have construction factors relative to the Gulf Coast in the area of 1.6 to well over 2 times that of the Gulf Coast construction cost versus a 1.3 to 1.4 factor frequently used for Alaska. Nevertheless, the OPEC countries will build some plants and will be entering the world market. But to put this in perspective, however, even if two or three projects are built in Saudi Arabia in the next 10 to 15 years, and let's say 2 or 3 or 4 more plants in other parts of the Middle East, this will as you will shortly see, reprepresent only a very small percentage of the world market and certainly not the kinds of production quantities that will dramatically alter the world situation and something to be terribly concerned about.

And so, and then there are other problems, of course, is that the OPEC countries are somewhat unstable in the eyes of a lot of companies that would like to produce there and the fact that these companies are over in the OPEC countries like Saudi Arabia and Iran and Abu Dhabi and so forth, means they are looking for alternatives to what they would like to continue to do on the Gulf Coast and cannot do and that is I believe also why we were able to attract quite a bit of attention to a project in Alaska.

Now we will start looking at the specific markets and market projections that we are contemplating for this project and we're basing some of our thinking on. The next slide is I think interesting because it shows you the power of geometric growth as it were. The 1980 figures for ethylene, propylene and benzine, the three most important petrochemicals, are I think accepted by everybody who knows the business as being quite representative of what will be the situation at that time. Assuming a growth rate as I've indicated before in the area of 5 to 6 percent per year and multiplying this to the 10th and then to the 20th power, which is what you're doing, you arrive at very large amounts of ethylene, propylene and benzine. Now we may be wrong about these projections, though

AGP 559371

we are not out of line with other people who make these. Maybe the growth rate in the 90's will only be three or three and a half percent. But even if we talk about ethylene being only 70 billion pounds, you can still see the huge amounts of additional capacity required just for the United States alone. And when we contrast that with the ALPETCO case I've shown and as you see we show it as a case -- there are other cases that make less and more ethylene and propylene. You can see what a relatively small percentage of U. S. production this actually amounts to and this will be shown again in another slide.

The next slide is taken from a presentation that Union Carbide made to the security analysts a number of months ago -- it's still quite up-to-date. Again it shows the supply of ethylene on the upper part and the reason it (indisc.) each project or projects each year at a certain amount of capacity, the lower (indisc.), the smooth line represents the effective capacity because these plants will operate somewhat lower than the rate of capacity and the lowest curve shows the demand projections -- the reasons the curves digress a little bit is because this really should be shown on a log lock scale to be most properly shown. But in any case, the point is that every three or four years supply catches up with demand -- I'm sorry, demand catches up with supply, unless more plants are required.

The next slide please.

I indicated before we were looking at the U. S. West Coast and here Chem Systems has made a number of studies and facts. I gave a speech at the National Petroleum Refineries Association Petrochemical Meeting last March from which this is one of the presentations or exhibits and this shows that the West Coast market is large and getting larger. None of the materials I show here are actually made on the West Coast today with I believe one exception, polyethylene, which is made in very small quantities, almost negligible.

The next slide please.

It shows the same situation in numbers roughly, again showing this high growth for petrochemical derivitives, ethylene, (indisc.), polyethylene and styrene on the West Coast. You see, for example, polyethylene demand now is in the area of 700 million pounds, slated to grow to 1.9 billion pounds. These demands must come from somewhere and we believe that Alaska, an Alaskan plant, could supply a certain percentage of these and we would only need to sell -- need to fulfill approximately 20 or 30 percent or less of West Coast requirements in order for our project to be viable. The number of companies who market on the West Coast would be interested in obtaining products from other sources so our thinking there is not to

become a new marketer of material but work with existing marketers of these materials on the West Coast and we have already talked to them and as Gordon has said before they have expressed considerable interest in working together with us in the form of joint ventures or other business arrangements.

Moving out to the Pacific basin countries, this next slide is our estimate of net import requirements for a number of these countries and that other slide that I showed you, showed for example that carrying all the plants that have been built and looking at the man increases, the region has a need for net import of a fairly substantial amount of these technical petrochemical and this again therefore the market that we want to go after.

The next slide summarizes the ethylene requirements for both of these markets and shows that this for the U.S. West Coast and for other Pacific basin areas totals of ten World Scale ethylene plants are required through 1990 and we are thinking in terms of one plant at least for the time being so that we are looking at selling--we are looking at ALPECTO fulfilling only 10% of this new market (indisc)--expanded marketed requirement through 1990. And in the last slide we show therefore a number of possible chemicals that could be made in Alaska for fulfilling either or both the U.S. West Coast market or the Pacific Basin market and I think this will explain to you why we have not yet chosen the final configuration for the plant. We must decide which of these chemicals to make and we can't make them all because we want to build world skilled facilities which means probably only 3 or 4 of these types of products should be made and they should be made in fairly large quantities. Now leaving the market and addressing ourselves next to the question of economics and Alaskan economics, which has been certainly criticized in some of the articles I have read in newspapers and some of the statements that have been made. Such statements as ridiculous to build plants in Alaska because of markets elsewhere, etc. also that petrochemical should not be shipped all around the world, they should be made where they are consumed. Well, there are some falacies in this, although I must admit, it does represent some national wisdom of the--perhaps the 50 and the 60's and early 70's. We had an event that occurred in 73 that has changed a lot of things and you know what it was. The ALPETCO Companies are starting to become interested in building petrochemical plants and so a lot of petrochemicals are going to be shipped all over the world. Furthermore, the world trade in petrochemicals was always very large and in fact, contributes very very substantially to the positive aspect of our balance in trade. Were it not for our exports of petrochemicals our balance of trade would be substantially worse. This also, I think, is important to know in connection with some comments that were made that for every barrel of oil that we can turn to petrochemical and export to Japan we have to import another barrel of oil from the Middle East. That's true. However, the value to the U.S.of petrochemical export is roughly five times the value of the oil

AGO 559373

that's imported and so we gain, we have a 5 to 1 leverage in terms of the U.S. balance of trade for converting oil into petrochemicals.

The next point is just how unfavorable are the economics in building a petrochemical plant in Alaska and we fully recognize that there is a disadvantage due to the higher construction costs in Alaska. What we feel are mitigating factors, the factors that will turn the situation around are as follows:

1. We know that the Japanese petrochemical production is expensive because they must import their feed stocks from the Middle East and have very high transportation cost. We feel that an Alaska plant can be competitive in shipping petrochemicals to Japan.

Secondly, as I indicated to you, the logistics in cost of shipping petrochemicals from the Gulf Coast to the West Coast which goes either through the Panama Canal or by hopper car, by rail from the Gulf Coast of California are high and figures indicate that it would certainly be reasonably economic relative to those transportation economics.

Next point is, as I said before, the economics of building petrochemical plants in OPEC countries is high yet they are proceeding. So what really is happening is the world is changing and that petrochemical plants will be built more and more in areas where the feed stocks are because these areas, likely not, in most cases, ship all of their feed stock to world markets that would like to use these feed stocks to aid in their own industrialization program and I think you might say, being accused of being in favor of a project that might have questionable economics could be turned around and could be restated as saying we think that it would be important to find out if it would not be possible to build a viable economic petrochemical facility in Alaska. Because we have a feeling that it can be done and I would like to try it and ALPETCO is taking all the risks in order to be able to do this. And we further believe, as Gordon as indicated, the feed stock security that ALPETCO and it's proposed partners will receive will in our judgment offset the economic penalty that will undoubtedly occur to a subminor extent due to an Alaskan petrochemical facility. Finally, to answer a comment along the lines that well, this facility will be built and then it won't be viable and then you know the State will be stuck with a facility that will not be economic. It is our judgment, working with banks and with financial institutions and lenders, there is no way and I think the bankers will address themselves to this at a later point, there is no way that they are going to agree to lend this kind of money we are talking about here unless they completely satisfy themselves that this facility will be economically viable. The banks do not want to get stuck anymore than manufacturing people do.

A final point I would like to talk about briefly, which I alluded to before, relates to gas liquids versus petroleum feed stocks.

This has been discussed at some lengths in the Press and elsewhere and is certainly of interest to Alaska because of the North Slope gas and the extraction of gas liquids that has been proposed.

We don't know all the answers on this by a long shot and I think the reports that have been prepared by various consultants including Gardner and Moore, Salidus (ph) Battelle and others don't all agree with each other either which just shows that the problem is complicated. There are a lot of variables that relate to what the final well head price of gas is going to be, what's going to be the price of gas in the United States, the diamond or the lime, the amount of gas liquids that can be left in the gas, the amount of gas, ethylene, that can be extracted and so forth. Again we don't know the answers and we think there is a lot of uncertainty about this and it's impossible to make any firm plans on this. But we can say some things about it that I think go beyond the specific timing and economics.

One, ALPETCO is interested in cracking gas liquid if they were available to ALPETCO and if so, this will be possible because the cracking furnaces that ALPETCO plans to build will at least in part be designed to crack gas liquid if and when they are available to ALPETCO.

Secondly, the amount of gas liquid that are going to be available no matter whose numbers you look at are going to be very ample. There could be enough there to build a project along the gas pipeline if that turns out to be reasonable and economic as well as cracking gas liquids in the coastal region where ALPETCO plans to build a plant. The projects are not at all competitive because neither one of them serves the Alaskan market anyway. The markets that are being served from Alaska are the world markets I tried to depict in my slides and since there is plenty of feed stock in Alaska if one project makes sense, probably two projects would make sense. Not a market question, strictly an economic question. So we don't think these projects, if the gas liquid project were to come about, we do not think it would become competitive if it's decided to extract liquid and to build an ethylene plant for example ALPETCO could even take the ethylene by pipeline from that location and back out again feed stocks from its own crackers. This project could work with such another project on gas liquids with no trouble at all and this is what our planning is based on but the difference is the ALPETCO project can proceed right now, its based on petroleum feed stocks. Petroleum feed stocks are being used, as I said, in 90% of the world's petro chemical facilities and we think, that certainly there is nothing wrong with that and in fact, there is some positive features because from petroleum feed stocks you make not only ethylene but you make a lot of propylene, benzene, butadine (ph) and we are looking at a whole spectrum of products where cracking gas liquids really make primarily ethylene and a small amount of propylene.

Finally, on marketing strategies, this has been covered to a considerable extent by Gordon. I've talked about the West Coast and Japan but we do have some other thoughts to communicate to you on Japan and here I would like to introduce Mr. Tydings who has a special background in Japan as a special consulate to the Japanese Embassy and in Washington with a great deal of background in U.S Japanese trade relations and a member of the United Nations Consul for Population Activities. I would like to introduce at this time Mr. Tydings.

Excuse me, one minute. Would the continuity of your presentation be affected greatly if we hold him for about 10 minutes?

Not at all. We will break for ten minutes.

(OFF RECORD) (ON RECORD)

Hear his testimony and answer questions until tomorrow. So what the schedule will now read tomorrow at 1:30 Commissioner LeResche and Bonard Lord (ph)3:30.

[Whereupon discussion ensued among the members as to the the meeting schedule]

JOSEPH D. TYDINGS:

Senator Colletta, Representative Miles and members of the Special Committee. I appear here as a special consul ALPETCO. I also appear as one who has some experience in the legislative branch of the State Government and the executive and legislative branch of our own government. I'm also legal consul in Washington for the Japanese government on matters relating to trade with the United States and consul in Washington for the Kaydonrins (ph) which is the Japanese consul of Industrial Organizations on energy matters, Japanese Federation of Power Companies, Japanese Atomic Industrial Federation, and the Japanese Committee on Energy Policy Promotion, which was organized and headed by Ambassador Sheba (ph) until he was just made Czar over all trade negotiations, industrial matters and related Governmental Reorganization. I'm also representing and consuling ALPETCO with respect to this joint venture with the personal approval and encouragement of the Prime Minister of Japan and the approval of the Chairman of the Energy Policy Committee of the Kaydonrins (ph)

Now there are significant strategic aspects to the marketing of this particular plant and this particular project as they relate to the Japanese people and the Japanese nation. Let me just

refresh your recollection just a little with a more recent history of Japan particularly since World War II. (Cough, indisc) a remarkable degree of energy and know how, Japanese people have been able to rebuild their country after World War II into one of the principal and industrial leaders of the free world. But today they are essentially a nation which imports raw material, adds value to them, and exports them. And the most vital raw material in the Japanese list of imports are the energy raw materials. Japan is forced to import over 90% of its fuel oil and its energy of fuels, other than a little bit of coal they have there. Thirty seven years ago an embargo on oil to Japan by major countries in the world was sufficient to send them to war. That's perhaps, in today's concept, an over dramatization. But the strategic importance of fuel oil feed stocks of petrochemical facilities cannot be over emphasized as it relates to the Japanese people particularly in the 1980's.

The Administer of International Trade and Industry meeting recently issued some statistics which will relate to the Japanese need for increased fuel oil by 1982. And their shortfall in 1982 will be a million and a half barrels of oil a day. Sometime between now and 1982 they've got to find that source of additional fuel.

I think perhaps a word about the relationship in Japanese context between the Government, Kaydonrin (ph) or the Industrial leadership of the country is in order. Since World War II the political leadership of Japan has been divided by a Party call the Liberal Democratic Party. This Party, I would say is a sort of a broad-based philasophical conservative coalition. It is very closely related to the Kaydonrin (ph) or the Japanese Consul of Industry. It is inconceivable that any final decision with respect to the opportunity to participate in so important a project relating feed stocks as this would be made without joint participation by both the government and Kaydonrin (ph).

There is another aspect to the Japanese strategic position in the world today which indirectly relates to this and that is the unique relationship between Japan and the United States. As you know, under the treaties negotiated under General MacArthur at the conclusion of World War II, Japan has not rearmed. Japan's principal trading partner is the United States. The Japanese government and the Japanese people value their relationships with the United States very highly. They are very cognizant of the tremendous strains which have been placed on that relationship by the current trade in balances and particularly by the Japanese exports to the U.S. a number of important commodities which have very strong political constituency. The Japanese government is very aware of the steel caucus in our House of Representatives and in the Senate. They are aware of the constituency which relate to television products, shows to a great variety of U.S. goods which have been competing and not too successfully with Japanese goods in recent years. They are greatly concerned with the possible retaliation from the United States with respect to trade barriers, which could be economically very, very disastrous

to the Japanese government and thus they have been seeking ways to increase their imports to the United States. There is a major trade delegation in Washington this weekend , sent here purely to try and foster imports from the United States to Japan. If you have followed the journeys and travels of our special trade representative and his deputy in the last weeks of December, you will recall that there was two major meetings in Japan, at which time the Prime Minister stated publicly that his government would make every effort to increase the imports from the United States and, as a matter of fact, he had a shake-up in his entire cabinet. So you have that fact of life of the Japanese government today quite aside from the strategic need of feed stocks or other sources of fuel supply, the trade-in balance and the strain put on you as a Japanese relationship.

Let me, if I might, shift to our own government and our own strategic posture in the United States.

We have seen in the last two years two things, we've seen a basic trade deficit in United States relationship with the rest of the world caused primarily by the need to import oil from the OPEC countries. But in those trade-in balances the great in-balance with the trading nations is between the United States and Japan. Up until a few years ago we were basically equal trading nations. And that Japanese in-balance has caused, as I indicated earlier, protectionist movement in our Congress which we have not seen since the 1930's. The Smooth Holly Tariff (ph) was originally a bill introduced by a Senator Smooth (ph) Representative Holly involving just one commodity in 1930 and before it was through the Congress there were 140 different tariff barriers on it and that led to the whole world breakdown in the 1930's of trade. Now, the position of our government has been since President Eisenhower right through every President, right to the present administration, to try and maintain the United States' role, preeminent role as the greatest trading nation of the world, and we still are the greatest trading nation in the world, and try and keep trade barriers at a minimun. But I can tell you and I think that any responsible reporter from Washington will tell you that pressures on free trade are greater today in Washington then at any time in 30 years. So that United States government has a very serious problem if it's going to maintain our posture as the greatest trading nation and that problem is made greater by the Japanese difference in the balances of trade. So it is this particular project, at this particular time, that is a project in Alaska which would market high value added products, such as chemical products to Japan, with significant dollar amounts, whether we are talking about 40% of the output or 50% of the output or 60% of the output of this plant, this would be a major contribution to the United States trade balances. This particular project at this time falls right in line with what our government is trying to do. We have basic ALPETCO proposal has been presented and briefed to the top career civil servants and our special

AGO 559378

trade representative's office, Commerce Departments, State Departments, Treasury, Interior and the National Security Council. We had to do this at a time when we are not the awardee of the contract, when we would have been basically one of the competitors merely to present proposals as basically presented to you and to the Royalty Board. Without exception reaction to our proposal is that it is on all corners, all four corners, consistent with the international trade policy of our government that when the State of Alaska concludes their deliberation, the decision making process and awards the contract, that the top career and the top decision makers in our government will consider what steps, if any, will be appropriate to take in support of this proposal in light of the vital U. S. national interest. They made no representations that it would be put on the formal agenda between the U.S. and the Japanese trade negotiations, but in my judgment, it is difficult to see given the consequences that it would not be given very serious consideration. In my own judgment, I think it would be on there.

To sum up what I have basically stated, the ALPETCO proposal as it relates to Japan, as it relates to marketing in Japan, is an ideal vehicle for Japan to increase its purchases from the United States which Prime Minister Bacooda (ph) has said they are trying to do and which I genuinely believe they are. It will help provide an additional source of feed stock, a steady safe supply pending on the type of negotiations, the type of joint venture which they may enter into which (indisc.) and negotiates with one or more Japanese groups. And (indisc.) the bottom line of the Japanese it could be a very highly profitable joint venture. From our point of view, the United States' point of view, this proposal is in line with the efforts of the special trade representative is making with the admissions of Dick Rivers and Ambassador Strous made in December which was basically to tell the Japanese government they had to increase their purchase from the United States, they had significant effort to reduce the inbalances and bring the trade balances in line, so that we have a proposal which is right in line with our own policy and which would offer, I think significant advantages to the Japanese people and to the Japanese government. I think it's important to know that the timing of the proposal as it comes in 1978 such as to make just about inevitable, a strong Japanese participation as a possible partner for at least some of the production of this complex. Thank you.

CHARLES O. HONIG:

We've talked about the management and the description and scope of marketing and the last point on viability of the project involves financing. From the beginning we have had as our investment bankers, Lehman Brothers, Kuhn Loeb and E.F. Hutton as our co-investment bankers. And as our commercial banker, we have had Chemical Bank and all three of these institutions have met with us and counseled with us and worked with ALPETCO beginning last July and they have attended royalty board meetings with us in Valdez, Anchorage and Juneau and they have met with us in

AGO 559379

New York and Houston and they've been posted almost daily on the progress of this project. So they are an integral part of it and we would like for them to address briefly what's involved in the financing and I'll ask first Tom Kenny, who is managing director of Lehman Bros Kuhn Loeb, if he will talk some about the permanent financing aspect. Tom --

TOM KENNY:

Thank you. Good afternoon, Ladies and Gentlemen. Charles introduced me as the managing director of Lehman Bros. Kuhn Loeb, Inc. This is a brand new firm on Wall Street. It was organized in December 1967 (1977) so it's about three months old. However, we have two predecessor organizations that have been around for considerably greater time than that. Lehman Bros. was formed in 1850, Kuhn Loeb Co. was formed in 1867. Both organizations were important investment banking firms during that more than 100 year period of prior to our merger in December of last year. Both investment banking firms were in a forefront of American finance raising capital during that period. More important American business enterprises in significant industry. And as Charles says we have been associated with this important project since its inception, and our thinking concerning the structuring and implementation of the permanent financing has not changed even though we've perhaps elaborated a bit on it during that period of time since we started speaking of it and what we are talking about is structuring a permanent financing as a project financing. I'm talking about the permanent financing for the project as compared to what the construction financing which is what my friends in the Chemical Bank will address in a few moments.

Now, we have told ALPETCO, and continue to tell ALPETCO, that given the approach that they are using that we do believe this project can be successfully financed on a permanent basis, using traditional sources of capital at competitive capital costs. What I mean is, of course, the interest rates and the other capital costs would be similar to those incurred by other high fray developments of this nature or any other nature in natural resources. As a project financing we would expect a considerable amount of support where the financial structure would come from long term supply contracts running to (indisc. cough) utilizing and using the output of this facility. This will permit us to use a capital structure that probably would be somewhat more heavily step oriented than equity oriented but we anticipated that but certainly there will be plenty of the latter also. In connection with that we would anticipate that there would be participations in the equity of this project or its component parts which you've heard some things about it today by the people who are using the product and entering into the long time supply contracts. Such participation and arrangements would not be unusual but to the contrary something I would expect to take place as Mr. Cain

develops these arrangements with what he has characterized as his partners in the thing. We have written letters in support of the applications that ALPETCO has been making into the various authorities up here. We stand by those letters, we continue to feel that the structuring as a project financing with long term supply contracts that we can raise the necessary money in the convential markets. These markets will involve (indisc.) issues of both taxable bonds and untaxable bonds. The total amount of the financing we anticipate may, aggregate as you've heard here about 2-1/2 billion dollars, however, we are talking about a project that is going to be accomplished over a several year period. It's also going to be accomplished in several discrete stages. The capital markets as we understand them at the present time and we think we do understand them, and particularly the U.S. long term capital market. That is going to be the major source of this money we think will, in fact, absorb financing of that magnitude without any difficulty.

CHARLES HONIG: Thank you, Tom. I also would like to call upon another investment banker who is Executive Vice President of E.F. Hutton, who also by the way served under both Johnson and Nixon as the public member of the National Water Pollution Control Commission, Jim Lopp.

JIM LOPP:

Thank you, Charles. You know our public relations firm put out a slogan that when E.F. Hutton talks people listen. Which people as you travel around the country you make great mention of that after reviewing the contract the State put together, I believe that when Alaska talks, ALPETCO listens. I--reviewing it suggested that if anything more was traded, I think we wanted to be in the spot of raising the financing of the State. You have a very financable contract at this point of time.

Because of the magnitude of the project, I thought maybe we might just mention a few of the assets of the E. F. Hutton Co. in terms of what we hope to be able to bring to the table to help to raise the capital that is going to be required.

E. F. Hutton Co. is about 75 years old and has 190 offices in the United States, 12 in Europe, has about 2700 salesmen with representation of about 500,000 or half a million, retail and institutional accounts. So we believe that we will be able to bring a lot of these resources to bear in the placement of the securities.

Last year E. F. Hutton Co. managed to co-manage in the placement of debt securities and equity securities 4.2 billion dollars. As my co-investment banker pointed out, we have been involved in this project since its inception and we have continuously supported the ability of this project to be financed given its economic viability. I think it's important for members of the Senate and House to understand that projects like this have been financed in

AGO 559381

the past on a project financing basis and maybe a few examples would be helpful.

Down Australia way, we've had very huge iron ore projects such as Savage River, Rogue River and Kummersly (ph) which has been financed on a project basis such as we are talking about here. In British Columbia you may be familar with the Four D (ph) coal project as well as the Lorne X Copper project which has been financed on a project basis. I think maybe one of the best analagous situations to what we are talking about here, is in Indonesia, 21 utilities from Japan, financed a billion and a half dollar L & G facility to supply them with gas for 20 years. This was 100% debt finance and Alaska Interstate who was involved in structuring this transaction, retained the 22% interest in that project. That basically is the type of thing that we are talking about here.

Now, interesting enough let's talk just a quick moment about where these funds are going to come from. The commercial banks are going to talk about their construction funds and revolving credit agreements. We also look for credit to come from suppliers, export financing, medium and long term debts, both taxable and tax exempt and we also believe, and we said this to ALPETCO, that we will be able to raise required equity to support the financial structure of this balance sheet that they have projected. The taxable debt will be provided mainly by, on a private placement basis, with life insurance companies, pension, profit and retirement funds. The tax exempt portion of the debt and we believe in some of the members of our organization under the banner of another firm, were involved in coming up with the idea of financing the facilities at Valdez on tax exempt basis and spent quite a bit of time on that. and we've taken the analagous facilities, docks, wharfs, and some of the infrastructure and believe that under Chapter 61, Title 44 of the Alaska law, we can finance maybe up to 350 million of this financing with tax exempt bonds. Now this is important to the economic viability or helps support it in that the debt rate on tax exempt bonds is some 2% below that of taxable credit. I think Charles, this would rap up my summary of it.

CHARLES HONIG:

Thank you, Jim. We'd like next to hear from our Commercial Banker and speaking for Chemical Bank is Senior Vice President, Grenville Paynter, who also likes to fish in Alaska.

GRENVILLE H. PAYNTER:

Thank you, Charles. I guess it is appropriate to mention a little bit of Chemical Banks pedigree.

We were started in 1824. We ended up last year with total assests somewhere in excess of 31 billion dollars, we were in excess of 100 million last year, we have capital funds in excess of a billion 6.

The short term or the intermediate term facilities that we are concerned with in the banking side are neither exotic nor esoteric

AGO 559382

but are very typical of the kinds of projects that we are looking at these days. They are ones that also many of our cohorts in the banking fields are familar with and we have discussed them not only with existing banks that work with Alaska Interstate but also with banks in Alaska and in other money centers and without exception, we've gotten great expressions of strong interest in these kinds of credits. There are three basic ones we are talking about. The first is at the request of Alaska Interstate, we've examined their situation to determine how best and to raise the amount of equity that they would put into ALPETCO in the beginning. We have determined that a hundred million dollars would be easily raised and we have also told them that we would make 20 million dollars of that available upon ratification of the contract to help them with or supply the money for the start-up cost.

We have further told them that we will take 50 million of that total credit ourself. We have indicated to ALPETCO that we believe that a bank group for the interim construction financing of the refinery could be set up. That under present plans a 400 million dollar commercial bank credit should be satisfactory. This credit would be set up against a take-out commitment from long term lenders. Of this 400 million dollars Chemical Bank would be willing to take up to 100 million dollars and would act as agent for the group of banks that would provide the remaining funds. Other forms of financing such as already has been mentioned, supplier credit would substantially fund the remaining short term needs.

Finally, we have talked with ALPETCO about the working capital requirements, the marketing, the royalty crude oil. This encompasses the phase during construction of the refinery after the company has met the bench marks Charles has referred to in his presentation. Our analysis leaves us to believe that a working capital line in the amount of a hundred million dollars would be adequate and here again, Chemical Bank would be willing to take up to fifty million of this financing. Needless to say, each of these various credits is subject to a satisfactory credit agreement. But in each case they are typical of agreements that we work with every day. I'd like to conclude my remarks by maybe restating my opening comment that the Commercial Bank role in this project is personally conceptionalized is a role that No. 1 we are familiar with and No. 2 we believe can be successfully duplicated on behalf of Alaska Petrochemical Co.

CHARLES HONIG:

Thank you, Gren. The closing comment on the matter of financing relates to joint ventures and I'll just briefly refer to a chart that shows some of the possibilities. This is different from Gordon Cain's chart on the refinery but in petrochemical complex but it shows various ways that ALPETCO can work with others in

putting together in Alaska this type of facility. For instance, we refer to the center part as the core of refinery and that would be primarily in that respect just sulfur recovery, sulfur removal and the ports and docks might be owned municipally or owned separately from ALPETCO, the utilities likewise. As Gordon said we might bring in a big brother partner, a chemical company who might agree to build a olefins plant or one who might be interested in the aromatic aspects. So there are all kinds of possibilities for joint ventures which will result in our associating companies as Gordon mentioned with know-how and money and experience in this particular area.

I'd like to ask Gordon Cain if he might summarize what we have presented today.

GORDON A. CAIN:

Senator Colletta, Gentlemen of the Special Committee, word summary suggests that we are reaching the end of this presentation which may be of some relief to you. So I won't take too long to do this.

You have decided that you want to process your oil in Alaska if you can do this without any penalty to the State. Commissioner LeResche and the Royalty Board have examined the proposals that you have been presented with and they have reached the conclusion that the proposal that includes a refinery and a petrochemical operation (cough-indisc) presented by ALPETCO is the best of the proposals that you have received. Some of the factors that might have gone in their consideration are that this will create three or four times as many jobs and three and four times as much tax money in Alaska as any of the alternative proposals. Also, as I mentioned earlier,the addition of these petrochemical facilities to the refinery improve the possibility of the overall project and increase the probability of success. Mr. Spitzalluded to the fact that this project is not competitive with and probably will help your ability to use your gas liquids later. We would be a potential customer for these gas liquids, we don't want so much of them that it would impose on--impinge on your other project if you decide to go ahead with it. We will both, the gas liquid project and our project, will be competing in a world market in which there are ten or fifteen other plants of the same size that we are and the fact that one of those plants is in Alaska and one of those plants is our plant, will have little significance. Whether this gas liquids plant that is competing with us is in Alaska or Indonesia is not going to make that much difference in the overall competition because both of us are only trying to get somewhat less than 5% of the market that we are dealing with.

Now, you have been told that our project is the best project but you still have a reasonable question is the best good enough.

Now is this best project one that is likely to go ahead and have a chance for success. Now, if we were talking about a project that is going on stream today or if we thought the future was going to be a continuation of the present, if we thought that there would always be a surplus of crude oil, if we thought that there would always be an over-supply of petrochemicals, we would not be here talking to you at all. It would not make any sense to build this project or to put this much money in this. But none of us and none of the experts in this matter, think that things are going to continue as they are now. Prevailing wisdom is that by the mid 80's there will be a shortage of crude in the world. As you can see, the growth of petrochemicals, even if you used the lowest probable growth, will require that there be on a world wide basis a plant like the one we are talking about, built every six months somewhere in the world just to keep up with the lowest anticipated growth rate. So that although a billion and a half, two billion and a half, three billion and a half dollars is a lot of money in the context of this world petrochemical situation, this is a relatively small part of the whole thing. And the question really is what are the things we have that would make this a viable project, make it possible for us to compete in the world market?

Now this plant will come on stream in the late 83's - early 84. By that time we think that there will either be a shortage of crude oil in the world or it will be obvious that there is going to be a shortage. And since people operate on the basis of what they expect to happen, if people think there is a potential shortage of crude at that time, a source of petrochemical that is located in a political stable region, political special to this context doesn't necessarily mean that everybody gets reelected. It just means that nobody siezes the plant. In a politically stable region that the market price will be a very attractive source of chemicals for users of petrochemicals.

Now, at that point we will have a plant that was completed in the early 80's. With inflation running like it is now, every one of the two plants a year after our plant is built will cost more than our plant will because of inflation. You will have a plant that will be producing petrochemicals that will be growing at at least 5% a year rate, we will be producing less than 5% of the requirement for the Pacific basin for these particular products. We are not looking for a great part of the market. We expect to have one, two or three very knowledgable partners in different parts of this enterprise and with all of those things we think that we can have a, we know that we can have a viable project. Now a question has been raised in the course of this, even with all of this, how do we overcome the disadvantage of the hard cost of operating in Alaska? And this is a very valid question, its one we have to answer for you and its one, equally important, we have to answer for the bankers.

Now, first, we don't think that the disadvantages in Alaska are nearly as great as the construction of the pipeline would suggest.

We hope and certainly intend that we build this for far less premium than the pipeline was built for.

Second, we expect certain things that will help us to compete with the rest of the world.

Mr. Spitz mentioned some transportation cost advantages which are significant but still not enough to close the gap. The financial people they think that we can finance this with more debt than the normal project. And this is an economic benefit But even that isn't enough to close the gap. The main thing that we have to close the gap is that we will be competing at that point, at least in part, with projects that are being built in Korea, Singapore, Middle East and other places like that, that at least have some possibility of instability and some possibility of interruption of supply.

Now, the project in Alaska certainly has less of that risk. Therefore, we expect that our plant with our partners will be their favored source of supply. We don't expect anybody to pay us a bit more per pound than they pay anyone else because they can't and stay competitive. But we do expect one thing that they can give us that will not cost them anything and that is to give us a larger percent of their requirement then the average. To give us enough--this is so that we can run our plant at a higher than average rate of the other competitive plants. Now, this doesn't sound like much but just some simple facts on this kind of plant. This kind of plant has a break even point of about 70% which means that you don't make any money until it gets up to about 70% and then you start making a lot of money. And with this high break even point it means that at 80% you make some amount of money. At 90% you make twice as much money as you make at 80%. So this is a highly leverage sort of operation. Now if we can run this plant at 10% higher than the average of our competitors, we can more than make up the Alaska disadvantage even if we assume some rather large disadvantages here. Now we expect to be able to do that because the people that we will have as partners and the people that we will have as customers will want to keep this plant alive, will want to keep this assured source of supply in being to the extent that these are Japanese plants. They will want to contribute to the improvement of balance of payments between us and the Japanese.

Now, with all these factors, with the organization we have, with the partners we expect to get and with the help of the people in Alaska, we expect to be able to make this a viable possible petrochemical project and to make Alaska an important factor in this part of the industrial world.

Thank you, gentlemen.

CHARLES HONIG:

Thank you, Gordon. In closing I would like to just flash on the screen for a moment the eleven recommendations, contractual recommendations that Mr. Miles' State Energy Policy Committee made last year. We believe that ALPETCO has -- we were conscious of these, as we negotiated the contract and we believe we have met all eleven of these contractual recommendations. And those were first that the contracts have a cancellation or termination provision which ours has -- that it require local training and hire, which it does; that completion of the refinery be tied to the sale of crude to assure there would be a refinery and this exists in our contract. That the in-value price be paid which we agreed to do. That there be compliance and security provisions in the contract which there are. That the point of delivery be LACT meter one, which it is. That there be no subsidy and there is none. That the method of payment should minimize the float of the funds and I assure you it does. That in-state fuels, use of fuels, be provided for, which it is. That in-state processing be required by the contract, which it is and that the quantity not be guaranteed by the State, and it is not. Thank you gentlemen. I apologize for the length of the presentation but there has been so much talk about it over a period of time -- we assembled these people here, we felt we should address it fully. Alright, thank you very much and as we stated in our opening remarks that we needed some information (indisc.)

CHAIRMAN MILES:

Thank you. I'm tremendously satisfied and pleased with the project. I don't think there's any doubt about it, especially after what we heard today. Perhaps one of them would like to comment on how the effect of committing undiscovered reserves to the project would affect the financing.

CHARLES HONIG:

Jim?

ALPETCO REPRESENTATIVE:

Okay. Would you care to repeat that question please, I didn't quite catch it. The committing of reserves?

CHAIRMAN MILES:

Yeah, the 70%, the undiscovered -- essentially undiscovered reserves.

ALPETCO REPRESENTATIVE:

AGO 559387

Let's try and keep this in perspective. We are going to go out and raise 2-1/2 billion dollars worth of financing. The lenders under these loan agreements are going to want to have some assurance that the debt's going to get repaid. People who we are going to sell the equity to want to be assured they are going to get a return on that equity. Now the only thing that really could happen, once they put up the money, is that the crude oil is available so that it can be processed, sold and the profits made. And I think for any types of these financing, everyone that I alluded to in my remarks, the raw material has been first, and the most key ingredient --

you have to have the economic viability, the raw materials and the take of the product.

It's a three legged stool. You take away any one of those assurances and the stool falls down. So before anybody goes into this type of agreement on financing, they are going to have to understand that there is enough material there you can run through the plant and make the product of which the profit is going to service the debt. And so we were hopeful and we have been very hard on ALPETCO and we've lost. We wanted a 100% of the royalty oil out of Prudhoe Bay but we understood that that had already been committed and we wanted 100% of the other royalty oil because, as once again, there is no guarantee that the State can deliver oil. All you can deliver is what you get and we want to make sure for the financial viability of that project that at least you get 150,000 barrels a day of crude. Because I tell you when we shift the other way the lenders are going to say to us but how do we know we are going to get a sufficient supply of crude to be able to serve--you know, to run this refinery. Really, everything we've said is based on our supply of crude and that's really the foundation of where we start. We've got to have that supply of crude.

CHAIRMAN MILES:

Some of that is undiscovered yet.

UNIDENTIFIED SPEAKER:

That's right.

CHAIRMAN MILES:

Then your--that doesn't really--it obviously doesn't cause the financial people too much of a problem.

UNIDENTIFIED SPEAKER:

What undiscovered? Well, to the extent it continues to be discovered it will be beneficial to us. Right now the reserves that we've heard about seem to be in sufficient supply.

CHAIRMAN MILES:

Yeah, I think we all expect more oil but it is a certain, a little bit riskier than taking 150,000 known (indisc)

UNIDENTIFIED SPEAKER:

It gives us more assurance however than not having any.

UNIDENTIFIED SPEAKER:

Okay.

UNIDENTIFIED SPEAKER:

The more assurances that we can have, the better off we are.

CHAIRMAN MILES: Mr. Chatterton.

MR. CHATTERTON:

Thank you Mr. Chairman. I apparently need a little bit of clarification on an obvious misconception that I have. I believe that I heard you Mr. Lopp say that the project can be financed given its economic viability. I can understand that and I heard you, Mr. Paynter, say that subject to a satisfactory credit agreement why you could support it. Now, that's what I heard. Now, have I miscontrued this? You have not given this your stamp of financial approval yet? Is that correct?

MR. PAYNTER:

No, we haven't given our stamp of approval based on the assumptions that I made in my remarks and I think just reiterated.

UNIDENTIFIED SPEAKER:

And if I can talk to.....what I said.....

MR. HONIG:

This is Mr. Paynter ....

UNIDENTIFIED SPEAKER:

Oh, I'm sorry. That's okay. I apologize.

MR. PAYNTER:

We, of course, on the short term side look to the long term take-out and if they are satisfied, if they are able to sell to long term investors and long term lenders the note, the equity, the wherewithall then the commercial banking side of this is taken out.

UNIDENTIFIED SPEAKER:

Okay. Together with all these ifs why everythings fine.

UNIDENTIFIED SPEAKER:

That's right.

(Indisc.-interrupted)

CHAIRMAN MILES:

Mr. Chatterton.

MR. CHAT CHATTERTON:

Thank you. One question to Mr. Norris that may sound a little bit not connected with the subject dependent upon the response. Mr. Norris, your parent company is Haliburton (ph). To your knowledge

AGO 559389

is any division or subsidiary of Haliburton (ph) engaged in the exploration for oil, production of oil and gas?

MR. NORRIS:

No, sir.

MR. CHATTERTON:

Thank you. Thank you, Mr. Chairman.

CHAIRMAN MILES:

There is a clause in the contract 2.6 Delivery of TAPS Fill by Seller, which essentially says that the State will supply trans-Alaska system pipeline fill and storage tank bottom requirements and that the State won't get paid till the termination of the contract. Twenty-seven years down the pike. How much oil is that--what actually is--what is pipeline fill and why shouldn't we get paid for 27 years? How much is it?

UNIDENTIFIED SPEAKER:

Well--this is a product(cough-indisc) our negotiations and we wanted the point of delivery to be Valdez and the State of Alaska wanted the point of delivery to be at the other end of the crude oil pipeline because they did not want to be a shipper. And all of our arguments have been for the delivery to be at Valdez. So in exchange for our agreeing to take the delivery at LACT Meter I the State agreed we could pay for the line fill at the end of the contract period or if upon termination immediately preceding termination.

CHAIRMAN MILES:

How much is that?

UNIDENTIFIED SPEAKER:

It's about -- well it's 85% of 1/8 of--in dollars it's about 9 million dollars.

UNIDENTIFIED SPEAKER:

But by the time it's ultimately paid for it will be paid for in the value of the oil at that time so if oil is $20 a barrel then it will be paid for at the rate of $20 a barrel (indisc.-interrupted)

CHAIRMAN MILES:

By unaminous consent we certainly appreciate the presentation....

(End of Meeting)

SCOMM

#14:9

Alaska State Legislature

POUCH Y, STATE CAPITOL
JUNEAU, ALASKA 99811
907 465-3800

TRANSCRIPT OF TESTIMONY OF

MILTON LIPTON

March 15, 1978

BEFORE THE SPECIAL COMMITTEE ON ROYALTY OIL AND GAS

Committee:

Senators:	Representatives:
Chairman Mike Colletta	Chairman Bill Miles
Pat Rodey	Chat Chatterton
Bill Sumner	Joe McKinnon
John Sackett	Charlie Parr
Kay Poland	Al Osterback

CHAIRMAN MILES:

I'll call the committee to order. Senator Hackney, would you care to join us? Senator Sackett? We'd be more than pleased to have you. We have with us tonight Mr. Milton Lipton. He's going to give us some of his observations on the contract. He's certainly well known to all of us. So with that, Mr. Lipton, please --.

MR. LIPTON:

I'd like to ask Mr. Kildrum (ph) Lilgore my ass~~esor~~ociate, to join me. I don't mind volunteering observations to the committee but if the questions get too difficult, I'm going to throw them at Dick.

Your committee's obviously been close to this issue for a long time, a lot closer than we have been and when we met the latter part of January, you asked me if I would comment on the subject of the oil royalty contract. At that time it was still in the competitive stage and I offered some very general observations on what I saw were the critical considerations involved. I will not repeat myself to you.

UNIDENTIFIED SPEAKER:

Mr. Lipton, I'm having a little bit of trouble hearing in the

back.

MR. LIPTON:

Well I'd be glad to address myself to the ALPETCO group, but that would mean turning my back on the committee. Does this do it, does this help?

UNIDENTIFIED SPEAKER:

No, I think that's just a tape recorder. You have to move forward.

CHAIRMAN MILES:

You just come on up.

MR. LIPTON:

I'll try to talk louder, not better but louder. Really, we have put together, I think, three observations about the contract that is now in front of you. And I think one footnote to the three observations, and I'll try not to be long-winded about these, and then place myself at your mercy for whatever questions you would like to ask.

I start with the first observation which is that if the royalty contract placed before you is approved by the legislature and if it comes to fruition, there are some very definite advantages for Alaska. And I see these as especially significant in the light of the fact that when the issue or the subject or the possibility of the sale of royalty oil as the basis for some kind of industrial establishment was first (indisc. - cough). The companies that are most likely to be parties of the first part, rather they are oil companies or chemical companies, were extremely reluctant to come forward with positive commitments. We know this because among our clients were companies that really discussed the prospect and many of them looked at it, some seriously, some less than seriously. But in light of the fact that the companies who might have had the best controlled markets for the disposal of either energy products or chemical products were themselves reluctant or didn't visualize the prospects as particularly conducive or were reluctant to make the investment, that in consideration of all of this, it stands as significant that there is a contract before you with a group who if they can perform and if it comes to fruition would contribute something that otherwise you have been unable thus far to get. And that in itself I consider to be a plus for what has been the process of investigation, discussion and negotiation up to date. That's my first observation.

I skip to my third observation, and that has to do with how we see the prospects for success. Now I speak of this, not in terms of the probability, it is no part of our role to tell you what the chances are of this thing coming to fruition, but I think it is important to evaluate again what the difficulties and what the problems are. Particularly, because in all of the discussion and in all of the representation there has been a great deal of possibly and probably, and sometimes not coming to what we think are the realities of the project, or any project faces.

The disposition of chemical products on the West Coast is, I think, a reasonable possibility; that is to say there is a great market at the present time which is supplied by indirection out of capacity in the Gulf area. The market is undoubtedly growing. One can argue about rates of growth in the United States or in world markets, and I put that aside. I don't think this is a numbers game. But there is a potential market on the West Coast.

The difficulty, of course, is that the companies who are in most direct control of the market are not the ones who are participating here. It becomes a matter of whether one can establish the relationship which makes it possible to do.

I think that the foreign market, which is discussed, which is essentially the western perimeter of the Pacific, is probably the most elusive and the most difficult one. It's not because there isn't going to be a growth in chemical demand in Japan, Southeast Asia, and the Pacific basin as a whole; there will be a considerable increase in demand. But the areas from which that chemical demand can be supplied looks to be ever so much more attractive than out of Alaska. I'll give you our quick thinking on this.

The expansion of chemical capacity to serve the markets by Japanese chemical companies is undoubted. It is going to happen. The question is from where. For a lot of reasons we think that the major expansion of chemical capacity by Japanese companies will not be in Japan. It will be outside of Japan. There are limitations on what can be done in Japan for a lot of reasons, not the least of which has to do with siting problems, has to do with environmental problems that are very, very real. But it means that if the Japanese chemical companies are going to export capacity, they will export capacity to those areas where it is most strategic for them to do so. And that means either exporting the capacities, say, into Southeastern Asia, the whole range of areas all the way from Taiwan, through Singapore, potentially through Indonesia, where in a sense they are in the direct line of the main flow of feedstocks from the Persian Gulf area, the Arabian Gulf area, to their markets. Or, they will participate directly, or indirectly, in the expansion of

petro-chemical capacity in the Middle East itself.

I think there's some misunderstanding about what the incentives are for investment in the Middle East. It's true that capital costs are relatively high there, but the decisions of companies whether or not they put their capacity into the Middle East, where capital costs are high and where transportation costs to market for petro-chemicals are high, better moving the crude oil from the Middle East to Southeast Asia, the naphtha that comes with the crude oil, you process the naphtha. Given the transportation disadvantages and given the capital disadvantages, the reason that the companies are considering going in there is not just that they get an assured supply of petro-chemical feed stocks (ph), which is the argument in behalf of the Alaskan facility, if in the future period of time there is question about the continuous availablity of feed stocks (ph), shouldn't you go where it is available - Alaska or Middle East? It is more than that. It's that there is a political thrust on the part of Middle East governments - Iran, Saudi Arabia, especially - to develop an industrial profile for reasons that are difficult to follow. I don't know the reasons for it, but to develop an industrial profile which somehow is a reflection, also, of their importance in the world at large. They aren't important in the world, because Saudi Arabia is going to be pivotal to the supply of oil and gas for the world. Why an industrial profile that reflects it? Certainly not to create unemployment. They don't want unemployment of Arabs, and they have great concern about the importation of foreign labor that might work there. But I think there's an important psychological urge that, if Saudi Arabia is to occupy as pivotal an economical and political role in the world as they now believe they can, and as the world outside tells them they must, that somehow they ought to look the role as well as play the role, and this involves some kind of an industrial profile which fits in with everything else.

Now, to do that, they have not only to offer the feed stock (ph) for the petro-chemical plants, and as a considerable negotiation, what price ethylene to an ethylene operation, and how do you handle financing, more important than that, and this is what brings in the Shells and the Mobils and the Dows and, in due course, the Japanese, that they're prepared to offer, in addition to the assured feed stock (ph) near the petrochemical plant, a collateral supply of crude oil for export purposes. The investment in the petrochemical facility will not only directly or indirectly overcome the competitive disadvantages, which you have in Alaska and which they have also (high capital cost, high transportation cost), they can put in the at a very low price if they will, they can offer low-cost capital advances, but there is a hundred to a hundred and fifty thousand barrels a day of crude oil, which in the late 1980's will be available to the company that is willing to make the petrochemical or the refining investment. And this is what is bringing the facilities into it. And this means you will have, not as quickly as we had anticipated had been brooded about,

and not on the scale that originally went into the Saudi-Arab investment program. And, in view of the surpluses, neither the companies nor Saudi Arabia are that anxious to push the thing along, which is one of the reasons the negotiations proceed.

But there will be, in due course, a reasonable expansion of petrochemical facility in the Arabian Gulf and in the Persian Gulf, because the Shah will have at least one major facility. This expansion, which willy-nilly is going to have to move to world markets and which faces special competitive disadvantages in the European market, or the U. S. market, transportation problems, no quick mode of transportation, the kind of ocean-going carriers that are lowest cost probably couldn't go through the Suez Canal - what goes through the Suez Canal is higher cost transportation - plus protection in Europe by the Common Market for their own chemical industry, so worthily (ph) you are looking at the western rim of the Pacific, which is precisely what Alaska would hope to get to augment whatever the potential is in California. And if the export of processing capacity by the Japanese chemical industry to Southeast Asia, coupled with the competitive supplies out of the Persian Gulf are put together, what it means, in effect, is that the present capacity in Japan, which is both for domestic and export markets, becomes increasingly available for domestic markets, because the export markets get served out of the export capacity to other areas.

This is why we feel that it is extremely difficult to visualize the (indisc.) of commitment of Japanese, because given the proper terms and conditions, there may be certain commitments. But the way in which the competitive environment operates in '85 and '87 and in '89 when an Alaskan facility comes on (indisc.) and they may have to supply parts at not stipulated prices, but at what are called competitive prices, I think both volume and price-realizations are questionable. The point of what I'm saying here is not that I'm trying to tell you the odds of the project coming to fruition, that's not my point. I think that you've got negotiated, both by the State and by the ALPETCO group, as an imaginative combination of factors into a contract as you could get, particularly in view of the fact that nobody else was forthcoming. What I'm concerned about is my point two, which I now come back to. Namely, what are the risks for Alaska? Because, if the project can be put to fruition, but if the economics should turn out as complicated and as difficult as we think they will, then this raises the whole question of what the risk is for Alaska. So I come back to this, which is the in-between thing.

Yes, it's a heroic effort on both parties' parts, and I think a very carefully drawn contract.

Number three - we think there are problems, And, if we are right about the problems, but meanwhile the contract is moving forward, what are the risks for the State of Alaska?

I suppose that in the interim period. they are pretty much minimized by the terms of the contract. There are due dates and performance commitments right down the line. So how can Alaska really lose on it? For example, the ALPETCO group, which for reasons that I can only partly interpret, would like to have prior access to the crude oil before the facility is completed. Obviously, if they have that option, and in eighteen months they have met their commitments, they would only exercise their option for the crude oil if it turns out to be profitable for them to do so.

But, how much protection does Alaska have in this interim period? Well, the due dates are very clearly specified. There are certain allowances to the Commissioner six months at various dates (indisc.). But, you know, I rather suspect that if this group works as hard as they obviously intend to, that if there comes a due date and there is evidence of sincere effort, will Alaska at that time say, "Cut them off because they haven't met their commitment," or will you be more inclined to say, "Well, look, all the evidence of effort is there - one is on the verge, shouldn't we go?" Which means one may extend all of these due dates somewhat beyond the contractual terms, which may not be bad. The only question then is, for how long a period of time has Alaska, in a sense, given the first option for all proposals to this selected group and, during this interim period which may be assured is eighteen months, but may be as long as two years or two-and-a-half years, which in effect blocks out any alternative proposal. I have no idea if alternative proposals come in, and I don't weigh this very heavily. But in my own mind, as I visualize the progression through which one goes, one has to ask realistically whether a due date at which point performance has been completed or the contract is voided is really realistic. If in fact this group will perform, as I expect they will; that is, with diligent effort and always with the expectation that things will be coming through. But more importantly, your contract is a contract contingent upon a whole series of performance. The ALPETCO group must also look for the contracts which they need, both for off-take of products and for the commitment of funds, which, in a sense, are contingent,too. That is to say, as long as things continue to look prospective, one goes along.

What is a contract for the off-take of products? Specified products, specified quantity into a certain market at what? At a guaranteed price? Never. It's also got to be at a price which allows the buyer to be competitive in his own markets. Call it what you will - world market prices, competitive prices, whatever it is. And so long as things are running this course,

and in every stage of the game there may very well be a feasibility study, one goes along; which means the lenders do, the ALPETCO people do, and the buyers do. But, if, finally, this facility is built and if you have five difficult years in which the lenders can be satisfied but the profitability of the refining bill really isn't there, that is to say, there would have to be capital infusions to keep it running, does the group have the financial capabilities to weather five or six years of difficulty beyond which the project may work out fairly well? Maybe not, but it could very well be. Or, does it become the responsibility of Alaska, in a sense, to provide them with essential support in the expectation that things will be better. The light at the end of the tunnel and the way you do it is you turn the equation around. The equation today is that the feed stock (ph) costs are fixed. They'll make a profit by selling competitively. You may have to turn it around that the selling price of the products is determined, and in order for the thing to survive, you have to adjust the feed stock (ph) costs to what the market looks like. This, I think, is the risk of Alaska. I'm not trying to pre-judge it. This is not a forecast, but I think that if you look at the combination of realities which the group faces, it is less disadvantageous for Alaska, but the realities stop the project, in a sense, and made a good pass at a Royalty crude contract but it hasn't worked out. Then that always the prospect is leading you one step further and then Alaska gets in the position where it, willy-nilly, is party to the equity position of the project because it will be very, very difficult for a billion, a billion-and-a-half, two billion dollar project in which the state has a vital interest to suffer financial disabilities and maybe threathen some future viability, which is only two years down the road, a few years down the road, or four years down the road. This, I think, is what you must assess.

And, as I said last time, and I simply quickly summarize. In the state of the circumstances, if you the Legislators have significant doubts about the balance between the benefit to Alaska and the risk, I don't think Alaska loses too much by deferring the decision. This, of course, is contingent upon whether you think royalty oil will be available in the future, whether you think one or two years or three years of draw-down of reserves is going to prejudice your ability later on. But the way in which one sees the future suggests that the perception of all parties as to the value of assured access may improve over time. And, there's no question about it, that the success of this project depends upon the participation of other participants, and the stronger the other participants are, the more closely entwined they are, the more they appear as a party of the first part, the more chances there are for success.

What you are wrestling with here is outside financing, outside marketing, all contingent upon the performance of other parties

and with an imaginative and an agressive effort by the ALPETCO group, but with limited capabilities on their own, as we see it.

Now, just one footnote to all of this, and then I give you your crack at me. I say this because we have just come this visit and the previous January visit and last year and the year before with long discussions about the adequacy or inadequacy of the state's income tax. In reaching out at the income generated by operations here in Alaska, and there are bills to change the income tax - I have no idea where they are going - but let's assume now that the income tax remains as it is, which means that for any multi-state corporation the income which you can tax here in Alaska is not measured by the profits in Alaska but is measured by the allocation of their overall profits earnings allocated by formula through Alaska. And, as you know from long dicussions, the big deficiency in the formula is that the sales factor gives you virtually nothing. You produce a lot of oil, or you might refine a lot of oil, or refine a lot of petrochemicals, but very little of it is sold in Alaska. So the proportion of a corporation's, of a multi-state corporation's total sales, which are sold in Alaska and become very small. So little of the income is allocated here.

I know very little about the internal structure of ALPETCO now, let alone what it may be by the time the project comes to fruition. But to my mind it is quite conceivable that it will be engaged besides petrochemical operations in Alaska with at least transportation and perhaps some satellite projects. They would like to get as much of the down-stream investment up here in Alaska, but they may be involved in California. I don't know.

What I'm suggesting is you might want to consider that if the state feels positively inclined that you might at least consider that part of the arrangement between the state and the group shall be that the first sale of products out of the facility shall be made in Alaska. It doesn't mean it stays in Alaska, but it can very well be exported. But if the first sale, whether it's to a trading company or to whoever, takes place in Alaska so that one comes to reckon what the earnings are, subject to tax, apportionments, or anything else, that at least you have under your present income tax statute and under your present allocation formula, at least you have a leg-up that there is a reasonable proportion of the product produced in Alaska is also sold in Alaska so that for tax purposes at least it get allocated back here. Which means you're not increasing the tax burden on it, but what you're saying is you have at least a chance to identify and reach out and tax it. This is a footnote, and it comes up only because this whole issue of the income tax has been so much in the fore for such a long time and we've been pivotal to that discussion. So I think you may want to consider that.

CHAIRMAN MILES:

Thank you very much. It's always a pleasure to have you come before us. Are there any questions from the committee?

MR. CHATTERTON:

Yes. I'll strike out first, Mr. Chairman, if I may.

Unequivocably, Mr. Lipton, you feel that a sale of our one-eighth royalty oil, that there is a risk attached to it. A risk that we might end up getting less for that one-eighth than if we took it back.

MR. LIPTON:

There is a risk. There surely is a risk.

MR. CHATTERTON:

I'm curious if you are somewhat acquainted with the State of Alaska's Constitution. Over the years you've been coming up here, it more less states that the resources of the state belong to the people. I'm wondering if you would care to make a comment as to whether or not we, as a Legislative body, have the moral or even consitutional right to take a risk with the peoples' money, or would the people go after it.

MR. LIPTON:

Well, you put your questions very, very directly, and it's awfully hard for me to equivocate when you put them that way, and I can't. Yes, I think you have a right to take the risk because you always take the risk. You take the risk in every kind of a lease sale. You take a risk when you select the bidding variable for a lease sale. You take a risk when you decide on how you choose among tax alternatives. These are all risks. I guess, unequivocably, I've got to say yes you have a right to take a risk on this, also.

MR. CHATTERTON:

Okay, fine. Fine. Thank you.

MR. PARR:

Mr. Lipton, if I understood you correctly, I think what you saw as the main advantage of this whole contract operation is that you got a breakthrough. You finally find someone who is willing to stick his neck out and go for a petrochemical complex in the West.

MR. LIPTON:

Gee, you put it so simply, and I was so complicated. Yes.

MR. PARR:

Okay.

MR. LIPTON:

That's it.

MR. PARR:

The second thing. . . I'd like to paraphrase what you said to make sure I've understood it all. There's going to be growth in the Japanese petrochemical industry. Most of it is going to be exported capital growth. They're going to build the plants either in Southeast Asia or in the East. And those . . .

MR. LIPTON:

For a specific market. For a specific market.

MR. PARR:

And those plants are going to take care of the export business. The plants that have been formed that are rather old-fashioned, using naphtha which are now in Japan itself will be servicing their domestic market.

MR. LIPTON:

Increasingly, yes.

MR. PARR:

Yes. What is the general status of the ability of those plants remaining in Japan? Those domestic plants we have been told, at least, are rather old-fashioned, to compete with a modern plant now coming on the line; but coming on line in 1983? Given their advantage of being on the spot.

MR. LIPTON:

Well, look, it depends upon what the ingredient of the competition is. Uh, in many respects a depreciated plant has a tremendous competitive advantage over a new plant if you're talking about relative costs of production, relative costs of processing. It depends how you calculate the costs. If you're saying, if you're looking just at operating costs, they may not be that competitive. But if you're looking at the whole complex of costs that go in with a great deal of the capital investment written off, and

you're looking only at the incremental cost of operation, they can compete. Hell, some of our oldest plants in the U. S. Gulf are competing in world markets today. And, so

MR. PARR:

You mean, in that case, that the advantage of having depreciated their plants already outweighs their technological backwardness. Is that what you are saying?

MR. LIPTON:

I'm not even sure how technologically backward they are. You know, it's an interesting question as to which technology is going to be the most competitive. Because technology is also a function of the feedstock that you use. Now, you know the new generation of ethylene plants, which are coming on stream in the U. S. Gulf and which is proposed here, are gas-oil plants which, basically, have a somewhat higher capital investment required relative to a somewhat different mix. But it's not at all clear that the direction in which the world petrochemical capacity is moving is going to move more and more towards the heavier feedstocks rather than the lighter feedstocks. Because if you go towards the Persian Gulf or the Arabian Gulf, you're talking about a fantastic availability of ethane, which is lighter material. If you look . . . I don't want to get more complicated than is necessary, but, if you look at the projects for the development of natural gas and natural. . . LPG liquids. Now there's talk about can you have an LPG base petrochemical operation here in Alaska? It's one of the things that's been considered. The amount of LPGs which are coming out of the Arabian Gulf between now and the early 1980's firm, and prospectively by '85, '87, and '88 suggests that propane, which has never been the basis for petrochemical processing in the whole Eastern hemisphere, although there has been to an extent in the U. S. Gulf, may become a competitive factor for petrochemical processing.

So, it's very difficult. I really don't want to substitute my judgment for somebody elses. All I see are so many uncertainties in the picture. But it's very, very hard to say with the kind of confidence that I would like to say that if only you have an assured source of feedstock here in Alaska, that outweighs your competitive disadvantages. And your competitive disadvantages are very clear. You heard . . . I don't even want to repeat it. . . you've heard this so much. The question is, does the assured availability outweight the competitive disadvantage. It may for the Western hemisphere, and you may even get Japanese participation here for world markets, not on the Pacific rim - the Western Pacific rim, but for the world markets in the Western hemisphere. The Japanese are very active here.

They want to make an investment, which would be fine because they like to diversify their investment, and the Western hemisphere looks very good to them. But that's not the marketing output over there. And any way you look at it, you're moving against the mainstream of the flow of energy commodities and the buildup of energy values. You're pricing . . .

MR. PARR:

I'm sorry, I don't follow you.

MR. LIPTON:

The center of pricing for energy commodities and derivatives will be increasingly, it almost is today, but not quite, increasingly out of the Arabian Gulf. And as you move eastward, it builds up in cost. True. But, if you're going to move against that, it builds up in cost more and more as it comes toward the U. S. East Coast. And if you have crude oil out of Saudi Arabia, or whatever else, or the naphtha which is derived from the crude oil, or the gas oil which is derived from it, it all builds up in cost and, therefore, in value as you reach the U. S. West Coast. Well, you have a better competitive value in the U. S. West Coast, but if you start moving with transportation costs against that flow, you're moving further and further in the direction in lower cost feedstock (indisc. - cough) cost alternative feedstocks. Whether they are naphtha or whether they are gas oil or whether they are ethane in the Persian Gulf area, (indisc.) the Arabian Gulf itself, or whether they are LPGs.

MR. PARR:

You say moving against that flow you are talking about, in other words, trying to supply markets which are nearer to the Mid East. .

MR. LIPTON:

Nearer to the place where the price originates. That's right.

MR. PARR:

Now I'm with you. I think I'd like to look at this a little further.

CHAIRMAN MILES:

Mr. Lipton, in there, speaking directly to the contract, as you are aware the contract does commit some future unknown reserves. In light of the risks that we understand (indisc.) ALPETCO and the State of Alaska will be taking should it go ahead with the project, can you comment on the (indisc. - cough) that the State might have in committing those unknown reserves, the non-Prudhoe reserves?

MR. LIPTON:

Insofar as there is a question whether you will have adequate royalty oil out of Prudhoe over the duration of this contract, whether it's this contract or any other contract, if, in fact, it's the assured availability which offsets the known disadvantages, then nothing's going to fly unless you're prepared to commit the hundred of a hundred and twenty-five of a hundred and fifty. Which means also the right of first refusal over any deficiency out of the royalty oil from Prudhoe out of other royalty oil anywhere else in the state. That is, whether it's this particular project, or whether you say no to this, and Dow Chemical comes back three years from now. If you're going to offset competitive disadvantages by assured availability, you've got to assure availability.

Is there a risk in this? Sure, this is another one of the risks. And the risk is that, in effect, you are committing this oil to a particular project under specified contractual price arrangements, which may by 1988 or 1989, 1990, or 1992 look to be far more attractive than other alternative in uses. It is difficult to say. And again, all . . . I think if you want this kind of a project, whether it's this group or another group, you're going to have to give assurance of supply. It's a risk you take. I don't know how high I would count that risk. I think, in many respects, the contract is as carefully worded as it can be to minimize the State's risk. I mean,you're not going to get any bargains on the royalty oil, although in the light of unknown circumstances it may be that they will still be able to get it at a price for their facility, which is less than what the State might otherwise later on may have been able to negotiate.

CHAIRMAN MILES:

Let's talk about pricing for just a bit. When you've come down and talked to us before, you have explained your theory about the, and I can remember you doing it, . . the surpluses like this now, when it's going to be like this a little bit later on, and it was the availability versus the price, and you really didn't, we didn't have a contract before us. Can you comment on that theory insofar as this contract is concerned?

MR. LIPTON:

Oh, I still think it's the case. This group. . . again, I think imaginatively has foreseen what the world is going to look like in '85, '89, and '90, '95. Which means they are presuming they can take your royalty oil today, within twenty-four hours construct a facility, and sell the products in a world in which petrochemical capacity is way at surplus. So, therefore, seeing the time when, one, there will be less surplus capacity in the

chemical industry, a greater demand from products from new facilities at a time when the new facility, which has assured access, has got a leg up over a new facility that doesn't have assured access. So, they're willing to take their chances on the price equation because they think that this is . . . . So, they are looking very, very far ahead.

I guess what I said to you last time that the way in which corporations react to this future, and virtually everybody sees the future the same way. They have different years that they put onto it. The C.I.A. says a catastrophe by 1982- - - we're all going to run short of oil. The O.E.C.D. says well, by 1988 - '89 it's going to be tight, but there's going to be enough oil left. Everybody sees the due date as somewhat different, but everybody sees the probability of a tighter supply situation in the world of oil than (indisc.) is today even if there aren't acute shortages.

Now, when investment decisions are made with a sense of urgency, or when prices start getting bid up, doesn't depend upon the shortage being there. It depends upon how soon companies begin to see the shortage within there planning periods. If you've got a five-year planning period, and you see the shortage coming up within five years, well, that's at hand. So, what we're talking about is not shortages in the early 1980's but when companies will have to make investment decisions and begin to say, we'd better start worrying about what our position is going to be within the period of time that we make capital commitments for capacity. And there are very few that are doing it today. The ALPETCO group is saying that, essentially. I believe so. What they are saying is, we're not building for today's chemical market, we're building for tomorrow's chemical market. And, if we've got this thing timed right, we come on-stream at the right time. And they are saying it.

But, you know, none of us know when year "x" is going to come, and you are being asked to make a decision on the same basis as the ALPETCO group has made their decision. That is to say, make your commitments now well in anticipation for a facility which will come on-stream when '83, '84, '85, at the best, and will run for about twenty-seven years more. Than whether that's the best time to make that decision, it's hard to say. And, if you're convinced that you have a limited amount of royalty oil with which you would like to achieve a purpose, and if you don't do it within this year, or at least a couple of years, you may not have the same oil to bargain with. Then, perhaps the time is now.

CHAIRMAN MILES:

What you're saying is that we are at a very similar investment decision crossroads that ALPETCO or anybody else is.

MR. LIPTON:

Absolutely.

CHAIRMAN MILES:

And we have to make a decision if the time is right for us to invest.

MR. LIPTON:

Sure. And, truly, if you want a facility which has to depend upon assured availability, and you think that all you've got is 12 1/2 percent of something under ten billion dollars at Prudhoe, and you've got to strike your bargain with that before too much of that runs out, then you don't have that much time. If you think that you've got a future here in Alaska, and it's not just Prudhoe Bay, but a lot of other things coming on, then the cost of waiting is perhaps not that great.

MR. OSTERBACK:

Is there anything else they could do with this crude oil? Would it be feasible for putting in a plant for rope and (indisc.)?

MR. LIPTON:

For what? I'm sorry.

MR. OSTERBACK:

For rope. You know, like nylon rope, poly-rope, web . . . Has anybody ever talked about that? The price has been doubling on that.

MR. LIPTON:

Not that I'm aware of, but if you have an aromatics plant, you've got the basis of nylon. Now how far you go. . . You know what the problem in Alaska is? That the closer. . . you have a very limited market here, a very limited market, so the more you go into finished products, you know. . . . To satisfy the Alaskan market is really the best thing that could happen to Alaska. Whether it's nylon rope or garbage bags, or almost anything which is petrochemical-based. This becomes a tremendous advantage for Alaska, because otherwise you ship out and you ship back and forth, but there is a real problem involved - how far you can push the downstream processing into finished products.

MR. OSTERBACK:

I'm not talking about shipping, but most of our rope now comes from Japan, Norway, Sweden, and that's a hell of a lot further than Alaska, if you're talking about shipping down to Washington, Oregon, and California. It's a lot closer.

I mean, I was just asking if that would be feasible to put these plants up.

AGO 559405

MR. LIPTON:

I don't know. From the standpoint of any group itself insofar as they can satisfy the Japanese market, if they can satisfy the Alaskan market, which otherwise is served from Japan, it's all to their advantage. It's all to their. . . The question comes down to scale and how they are going to put it all together. I really don't know.

MR. OSTERBACK:

Thank you, Mr. Chairman.

SENATOR HACKNEY:

Mr. Lipton, the prospect of not having to make a decision is always something that is dear to a Legislator's heart. Did I understand you to say that the sky would not fall if we were not to accept this contract and were to wait say, a year, two years? And, if we were to wait, how long should we wait?

MR. LIPTON:

With a certain amount of confidence, I will answer, the sky will not fall. Now that I answer the other part of your question, I have more difficulty. But, really, what is now being proposed? The sense of urgency is because of the availability of the oil. If you don't commit it, then whoever wants to put together a project has more and more difficulty of telling his customers and his financiers that the one thing I've got that other people don't have is the short availability. 'Cause the further you postpone it, the less assurance there is of availability, unless, come '79 and an open-lease sale and some successful drilling, and then everything gets turned all around.

But, I would think that a year or two is not going to be tragic for Alaska, except that, in a sense, what you're saying is we are turning our back on what has come to us in good faith, because we are hoping for something more. I would. . . This has to do with the psychological. But, the companies who might otherwise be involved with the ALPETCO group are not going to disappear in a year or two. They are still going to be there for ALPETCO or anybody else, or maybe come in as a party of the first part. I don't know, and I certainly don't hold this out as something of great promise.

I really don't think that . . . It's one set of uncertains against the other. There are risks in this; there are uncertainties if you say no. At least what you've got here is certainly a promise of sincere and major effort. I think that that's about the best that I could. . . There are uncertainties all over the place for them, for the State of Alaska.

CHAIRMAN MILES:

Can I follow up on that, Senator Hackney, if I may?

If the risks are there, I suspect similar risks will be there in a year or two. But, don't we come down to a situation where the oil becomes more valuable to the State of Alaska and, therefore, to any potential purchasers in a year or in two years?

MR. LIPTON:

Well, I think that out of a combination of world developments and U. S. policy, your oil will become more valuable. It will become more valuable as royalty oil and it will become more valuable for whatever purpose. The only question is whether you have dissipated a sufficient quantity of the Prudhoe Bay reserves and what you have left is royalty oil, looks to be less and less sufficient as the basis for a short availability. One can't turn his back on that. If it's assured availability that's going to overcome competitive disadvantages, then the longer you hold out the less you have to offer as assured advailability and the more it becomes speculative. The next time around, and the third time around, and the fourth time around you would have to offer an option on what comes up.

The other things come through relatively quickly, you're in great shape. Absolutely in great shape. I would say that if there were another major discovery in Alaska, so that you see your future further down the road than you do today, then you will have lost nothing. Except you will have lost the effort of a very determined group that are pushing like all heil, and that doesn't (indisc.).

MR. CHATTERTON:

Thank you, Mr. Chairman.

Mr. Lipton, I've been trying to figure out how to get to this question. I think I finally may have. If you were a party, the buyer party, to the contract as you have seen and probably understand, and everything in that contract remained constant, but gave you one option not in that contract now. . . say we could give you this option. . . to locate this complex that you are going to build in Valdez or someplace on the West Coast of the contiguous "forty-eight", what would be your choice?

MR. LIPTON:

The West Coast, beyond any doubt. If you had the same assured access to Alaska's royalty crude for a project on the West Coast, I don't think anybody would consider Alaska.

It's not a natural location for a petrochemical facility, anymore than Puerto Rico is.

MR. CHATTERTON:

If I heard the testimony on the last couple of days correctly and the answers to questions correctly, I think that the solitary, single big apple is the (indisc.) one that you mentioned, and I think that ALPETCO fully recognizes, and this is the long-term twenty-seven-year (indisc. - cough).

MR. LIPTON:

Of course, of course. Surely, surely.

MR. CHATTERTON:

And if we could keep the same supply, if we could lock it up right, or we could replenish it from new discoveries, would not a person be willing to make even greater sacrifices as the buyer may possibly be willing to make greater sacrifices in years from now than you are today, with the same guarantee....

MR. LIPTON:

Well, I think that, if you are right in our perception of the future, the closer we come to the time when the buyer sees close at hand the tightness, the more valuable assured access becomes. Yes. In the same sense that the parties that are negotiating in the Middle East today, on both sides of the fence, are rather prepared to drag the thing out and let it go, so, instead of coming onstream in 1981, it comes onstream in 1984 or 1986. There is no sense of urgency if they can keep negotiating, but get the thing going at a time when it's closer to when everything looks to be relatively more assured than at the present time. I think that's right.

MR. CHATTERTON:

Anyone in our case, with the contract we have, anything we can do to, and I can't remember the terms of the contract so this may be in order, but, if it's possible, why we would....you as the (indisc.) would certainly be interested in trying to extend so far as possible into the future the date that triggers off the twenty-seven-year period. And it may be the contract starts....

MR. LIPTON:

I'm talking now as a buyer, not as an investor. But it depends upon the buyer's circumstances. He has his own conception of when he needs products for further processing for integration into his markets. And, if he foresees that he is going to need new capacity either by construction or by purchase for 1983, he would just as soon start a contract in 1983. But given the way the surpluses are going, if you want to generalize, I would say, yes, you're better off later down than line than earlier.

MR. CHATTERTON:

Thank you. Thank you, Mr. Chairman.

MR. MCKINNON:

Mr. Lipton, to what extent does Article 2.3 preclude any other in-state use of royalty oil? It's the article that gives up ALPETCO's first option.

MR. LIPTON:

Yes.

AGO 559408

MR. MCKINNON:

Another (indisc.)

MR. LIPTON:

As I read the.... As I read Article 2.3, this, in a sense, gives the group the right of first refusal over other oil insofar as is necessary to make up any deficiency out of Prudhoe. They are not entitled to more than 150,000 barrels a day. So, it depends on what your total volume of oil.... it doesn't preclude other sales necessarily, but it gives them, you know, the right of first refusal.

MR. MCKINNON:

Is that only for a deficiency out of Prudhoe?

MR. LIPTON:

I think so. Either a deficiency or, in the context of the other articles, if the other oil is priced lower in royalty value, then they substitute royalty oil from Prudhoe.

(indisc.), do you read that....?

MR. MCKINNON:

Yes, that's the way I interpret it.

MR. LIPTON:

This is the way that I interpret it. But, basically, the state is not committing more than 150,000 barrels of oil a day.

MR. MCKINNON:

It's my understanding that the provision, assuming that ALPETCO was taking out 150,000 barrels a day, well, say, 100,00 barrels (indisc.) at a cheaper price, that ALPETCO would have the option of replacing 100,000 barrels of their 150,000 (indisc.) under Prudhoe, with the other 100,000 being offered at a cheaper price.

MR. LIPTON:

I think that's right. They may have the right to substitue. But, in toto, not more than 150,000 barrels a day.

MR. MCKINNON:

To what extent does that serve to extend this contract beyond its twenty-seven year deadline?

MR. LIPTON:

I don't believe it does.

MR. MCKINNON:

Well, the provision is that they all shall be offered to the buyer at the same price on the same terms and conditions as offered to third parties. Twenty years into this contract, the State makes an offer at a certain price with a twenty-year term....does that mean that ALPETCO gets the option to....

MR. LIPTON:

I would assume not. But, look, this is a legal interpretation of the contract. I would think that any reasonable man, which means not necessarily and attorney, would interpret this to mean the right to lift the twenty-seven year duration of the contract, and not because there is an offer of royalty oil elsewhere which may be available in the twentieth year of the contract, then for fifteen years they would have the right to extend it.

But, this is a legal interpretation of the contract. I would certainly not think that this is the intention of the drafters, either way.

MR. MCKINNON:

I didn't think it was, but I'm certain that it may have that effect.

MR. LIPTON:

Yes.

CHAIRMAN MILES:

Mr. Lipton, you mentioned before, and again tonight, that in any project of this particular nature the first five years may be rocky from a financial standpoint. They may be fairly tough.

MR. LIPTON:

Well, not necessarily. I mean there are capacities that come on-stream that are just at the right time of the cycle, and the first five years are magnificent. It's just that, again, I'm not making this as a prediction, I'm saying this is what the risk is for Alaska. But, if it works out that way, then it's a risk.

CHAIRMAN MILES:

I know you're not making that as a prediction, but you indicated that is a possibility and you use a five-year term (indisc.). When exactly does that five-year rought period begin? Does it begin after Legislative approval?

MR. LIPTON:

No, no. The five years I'm concerned about is the five years after coming on-stream, after starting. Because this is the time when all of the work has been done, the capital has been invested,when the contracts are beginning to be supplied. And then when you're worried about do you have

AGO 559410

the volume to get optimum utilization of your capacity and, therefore, relatively low unit costs so you're getting the prices you had anticipated. And, in the first five or six years, at the start of an operation like this, the cash flow can be decisive for the survival of an operation.

MR. PARR:

Mr. Lipton, I'd like to make some rather flat statements in coming back to things that have been (indisc.) before (indisc.) things that I've understood from you cannot, as near as possible, get yes or no answers (indisc.). If I understood you correctly, one of the risks to the State is that this refinery, or this petrochemical plant, may have difficulties somewhere along, (indisc.). And the State is going to have to wind up getting to bail it out by going in and putting in equity into the petrochemical plant.

MR. LIPTON:

No, I didn't say putting in equity. I thought maybe modify the price at which the royalty oil is being delivered to enable them to survive in the face of a difficult cash (indisc.).

MR. PARR:

I thought that you had said both of those. I misunderstood you, then....only the one of having to lower the price of the feedstock....that's the only one.

MR. LIPTON:

That's the most immediate one that occurs to me.

MR. PARR:

Looking ahead to 1983 or '84, or whenever (indisc. - cough), in petrochemicals, we are looking at a seller's market rather than a buyer's?

MR. LIPTON:

I'm not at all sure of that. Not at all convinced.

I know why. Because what you have is a projection of chemical demand, and, if you're projecting demand at six or seven percent, which is sometimes done, then what you speculate is that it needs so much capacity and, if it isn't forthcoming, you've got a seller's market. But turn it around. Let the expectation of a lot of companies in the chemical industry bid the demand goes up six or seven percent, and let demand go up four or five percent. The expectation of a six - seven percent growth means a lot of investment capacity. And the growth of four or five percent means you've got a buyer's market, not a seller's market.

AGO 559411

It's very.... You know, the chemical industry, among others, goes through fantastic swings. And one of the reasons that it does - one - not all of the reasons it does, is that you tend to have a lot of companies make simultaneous investment on the basis of the same expectation. And, if enough of them expect the same thing to happen, then all of them become frustrated because the capacity goes in.

MR. PARR:

Has that resulted in, let's say, petrochemical plants being built in bunches and skipping a number of years and being built in another bunch?

MR. LIPTON:

They tended to be, yes. Very definitely.

MR. PARR:

Everybody has seen the possibility all at once?

MR. LIPTON:

Pretty much so. There's a lot of that. There's a great deal of that. It's not.... As I said, that's one factor - far and away from the whole story. A lot of it has got to do with when oil companies went into the chemical industry and why they did and under what circumstances, and changes in technology. A lot of these things happen.

But, certainly, one of them is that, if you've got a competitive industry that sees things through the same set of glasses.

MR. PARR:

Another thing we've been told and, again, I'm using my own words, which may not be exactly the words that were used, but is it because of the imbalance in trade between Japan and the United States and the strong economic pressures that make Japan interested in taking a U. S. export of this sort? Now the question of the dollar and the yen thing didn't even come into this, this was even disregarding the dollar and the yen....

MR. LIPTON:

Yeah, sure, but there are a lot of ways Japan can do it. One way is to buy petrochemicals from Alaska, another way is to build automobile factories in the United States.

MR. PARR:

I didn't say, necessarily, in this particular instance....

MR. LIPTON:

I think it's a factor, but with all of the direction you have over industry from government in Japan, there's a limit to the extent to which public policy is going to lose to uneconomical commercial decisions.

MR. PARR:

I had gotten the impression from the testimony we had before that it's not such a marriage between government and big business in Japan, but it is a Siamese twin relationship. Which means that political decisions might well govern.

MR. LIPTON:

Well, maybe commercial decisions and government-political decisions?

MR. PARR:

Possibly.

Thank you, Mr. Chairman.

MR. LIPTON:

Excuse me, can I just expand on that for a moment?

The Japanese have always been interested in security of supply, and that's a combination of commercial and political decisions. And Japan has looked at Canada many times, under many different circumstances as a potential secure source of petroleum. Not necessarily to export to Japan because, come an emergency, they're not likely to, but if they have their own position, it becomes the basis for an exchange, or international balance of oil flows may be affected by their position. And there's no question but that it is widely believed, and the Japanese have held it out, that they will pay premiums for security of supply.

But, when it comes down to it, we've been involved in several of these projects. They will. But, the amount of premium that they are prepared to pay for security of supply is within manageable commercial limits. There is a limit to what they will do for it. And this had to do with the question of the Japanese investment in the (indisc.), that's all. All right?

CHAIRMAN MILES:

I'd like for you to go back over the industrial profile of the point that you made with respect to Saudi Arabia. I think I understand the situation on the West Coast and what large producers' situation is. I didn't fully understand the industrial

AGO 559413

profile point that you made.

MR. LIPTON:

On the petrochemical investment there?

CHAIRMAN MILES:

Right. Insofar as it may, or may not, relate to Japan and the other Pacific (indisc.).

MR. LIPTON:

First, let me start with the competitive disadvantages of a petrochemical facility in Saudi Arabia, which are very similar to the problem of Alaska. One is that construction costs and capital requirements are very, very high. Secondly, your market is a distant market. Therefore, if you have to move your chemical products to the market, it costs more to move the chemical products to the market than to move the feedstock embodied in the crude oil. So, you're bucking up against a transportation disadvantage.

Now, the starting point to overcome that is, particularly in Saudi Arabia, is the availability of huge quantities of ethane, associated with their whole gas-gathering system, all of which they've been flaring gas at a fantastic rate. Now, if you look realistically at a world-scale ethane and ethylene-related operations in Saudi Arabia, and try to calculate at what price the ethane would have to go into an ethylene operation in order that the combination of feedstock cost, capital cost, and transportation cost would allow you to sell competitively in Europe or Japan, you come up almost inevitably with negative prices on the ethane. In other words, the Saudi Arabian government would have to supply the ethane at zero price and maybe pay to take the ethane. But the Saudi Arabs, from the very beginning, negotiated not in simplistic terms. They were talking in terms of a combination of operations in which the ethylene project would be jointly owned, they would put capital into it, your derivatives would have a different financial structure. And, in fact, if you put together everything, which is a very low price on the ethane, and a very, very low price on the capital, which the Saudi Arabs would largely provide, you'd begin to get close, maybe, to a competitive situation. But, probably not. I doubt very much if, at least what we have seen, anybody would voluntarily move into Saudi Arabia and, even on that basis, just build a plant.

But what they have to offer in addition to that, and they've held this out since 1975, not in 1974 - in 1974 everybody was coming to Saudi Arabia and begging them - and by 1975 they were asking Saudi Arabia, if you want to marry us, what kind of a dowry do you have? You know, the things had turned around by then. Well what they have to offer is this. Look, if you won't do this on the terms and circumstances which we will

AGO 559414

together negotiate. In addition, the way we sweeten the whole investment project is by making available to you, not as feedstock to the project but for export purposes, for a given amount of capital investment, say a hundred thousand barrels a day of crude. Now, the further you push this project down the road, if it comes on-stream in 1985, you still may be in a difficult chemical environment. But, sooner or later, the project will pay out. But, meanwhile, if you can start gaining access to a hundred thousand barrels a day, a hundred-fifty thousand barrels of Saudi Arab crude, which is the most important and predictable source of world oil reserves for the long-run, over a period of time this becomes tremendously valuable. In the same sense, if you had said to a developer here in Alaska that we will sell you a hundred and fifty thousand barrels a day of royalty crude to do this investment, but, on top of that we will give you for export, beginning in 1990, another 50,000 barrels a day of Alaskan crude that you can do anything you want with, you've created an entirely different situation. This is what the Saudi Arabs are doing.

And this is why, what is essentially non-economic chemical capacity to a limited extent, and I don't think everything that's been booted about will not come to fruition, but I would guess three world-scale projects are reasonably well-assured at this date. It may come in largely because the Arabs have something else to offer, which is access to what will in the future be, scarce world oil reserves when the rest of the world is close to operating at productive capacity. The exspansible source of crude oil reserves production for the world will be Saudi Arabia.

CHAIRMAN MILES:

Let's just speak in terms of Japan now. From Japan's standpoint, would Japan rather have a source of Saudi Arabia or a source of Alaska?

MR. LIPTON:

Saudi Arabia. Saudi Arabia. You're talking about finite reserves here in Alaska. Unless, if things really work in exploration and turn Alaska into a fantastic producing province, is one thing, but we're worried about whether or not Prudhoe Bay will support twenty-seven years of a hundred-fifty thousand barrels a day (indisc.) crude. I'm not talking about Saudi Arabia producing a twenty million barrels a day, which was the expectation some years back, but whatever the demands upon Saudi Arabia, we are facing the year "x", and I don't know exactly when it is, when virtually most of the world will be operating at very close to capacity. And if the world is looking and saying, where will the next barrel of oil come from? - it will come from the reserves in Saudi Arabia.

And this is the most precious commodity they have, an expansible source of supply. It's not a bottomless barrel the way we thought in the 1950's, but it is, for the rest of the world, an expansible source of supply. And it becomes an extremely critical place for companies to go, and, if you'll notice, most of them go through Asia, which are going on into Saudi Arabia. They are companies that want either to improve or establish an off-take position in Saudi Arabia, which heretofore had been dominated by the members of ARAMCO (ph).

CHAIRMAN MILES:

I don't understand that. If we can assume for a moment we are talking about a hundred-and-fifty thousand barrels of oil from Alaska and a hundred-and-fifty thousand barrels from Saudi Arabia, I don't know if it's reasonable to make that kind of very narrow assumption. It would seem to me that, and again, relating to Japan, that they would rather have Alaskan source, if they could get the long-term commitment of.... mainly because of political stability.

MR. LIPTON:

I'm sorry, I misunderstood you.

If it's nothing more involved than an "x" number of barrels, and a price and competitive situation is about equal, they would rather have it Alaska, and they might even pay a premium... some premium for Alaska, but not very much. What I'm saying is it's not "x" barrels against "x" barrels. In Saudi Arabia it's "x" barrels plus. This is basically what they are getting in Saudi Arabia. They are establishing a position which gives them preferred access, not according to their feedstocks, but the off-take of crude oil for export purposes. This is the big thing. And in Iran, where so far the Shah has been unwilling to do this, the Japanese have been negotiating the petrochemical operation for years and years, and they haven't been coming anywhere on it. And only, I think, if they're going to be something which gives them more than just access to feedstock, because Iran is as unattractive a place to put export capacity and chemical industry as Alaska or Saudi Arabia. One doesn't go into these areas just on a purely commercial basis, I don't believe.

CHAIRMAN MILES:

Thank you.

MR. CHATTERTON:

Excepting the news of the last thirty-six hours or so, do you rate the "economic climate" in the Kingdom of Saudi Arabia any less stable than the economic climate in the State of Alaska?

MR. LIPTON:

It's a damn sight less stable than the climate of Alaska. Sure. I mean, if you're assessing political risks, there's just no question about it. No question about it.

MR. CHATTERTON:

Thank you. Thank you, Mr. Chairman.

SENATOR HACKNEY:

Mr. Chairman, the only time I ever heard Mr. Lipton really put in a box was the time when somebody sat at a position just about like this and they said, "Mr. Lipton, if you were sitting in my seat in the Senate, and this (indisc.) before you at the present time, and you had a green button and you had a red button, which button would you push?"

MR. LIPTON:

Remember what I said?

SENATOR HACKNEY:

Yes, I do. Push the green button. Would you push to green button in this case?

MR. LIPTON:

I don't remember saying push the green button. I think what I said was, if you'll give me a vote on everything else you can vote on the Alaska Legislature, then I'll vote on that issue.

MR. PARR:

Mr. Lipton, what you said, in effect, I think, greatly over-simplified, is we accept this deal. It's a pretty good contract. The real thing is ALPETCO is taking some calculated risks, and they are using their best judgment in this area. And the State, of course, if we go over the contract, essentially takes the same kind of risks. And you have not said whether you think it's a good risk or not. Maybe it's not in your field, I don't know.

MR. LIPTON:

See, I can't say that without being a Legislator who weighs everything in the balance. That's the difficulty. I don't want to overplay the risks here. And I do think it's a contract which, under the circumstances, was started from very little interest from anywhere around. It represents a maximum effort

AGO 559417

on the part the group, and it represents a maximum effort on the part of the people who drafted the contract to protect the State.

The question is, how do you assess the value of the whole thing? There are risks.

MR. PARR:

Nobody, who is very much interested in security, comes to Alaska in the first place. If they do, they don't stay. It isn't that kind of place. On the other hand, what I think most of us try to do is try to assess the risks as carefully as we can, and which, I think, is where we are hoping you can help us. If the gamble seems like a good gamble, we will go. If it's a poor gamble....

MR. LIPTON:

Let me try. You're asking me very straight-forward questions, and I try to give you straight-forward answers, but does it make my answers correct? Then I give you a judgment.

I think the biggest risk is that the contract will collapse, as we personally assess the probability of success as not all that great. And this is the risk. Now, what's the cost to Alaska if it does? That is, if an honest effort has been made and you've got this protection, and, whether it's eighteen months or twenty-four months, the ALPETCO group will be out a considerable amount of money. What has Alaska lost? It's a subtle thing. I guess you don't have the answer to that, but let me tell you the impression I have.

Alaska has been involved now in a series of episodes involving contracts with off-takers. And, first, it was on the joint resolution of the Legislature and then it was on the sale of the royalty gas - all for a specific purpose. Has Alaska suffered because of this? Well, at some point, if there is misadventure after misadventure, questions begin to arise about how solid is the thinking up there in Alaska about these things. If the contract doesn't come to fruition in the nineteen months or the twenty-four months, I don't think Alaska has lost a great deal. But, it's just become one more episode. But, I think that's about the greatest risk.

The other risk is that everything is going to go, and the investment's all going to be made, and it may lead to a very, very difficult time. And you may be faced with things which, under the contract, you do not anticipate; that is to say, a real sense of responsibility on the then-administration in the State of Alaska and the Legislature at that time that, hell, we can't let this go down the drain. Maybe that's not all so bad, because, if the thing does come to fruition - if

you have to hold for five years or seven years - that's not in the contract, but that's a risk you may have to do this, and it may not even be all that bad.

But, if you're asking me honestly to give you a personal judgment, that we've all discussed, it seems this is the way we assess it. Now you've got to decide whether, if the worst of these come to fruition, how much does Alaska suffer by it? I can't answer that question, but this is about the way which we will try to evaluate. The biggest risk and the highest probability, I think, is that it will not come to pass. What does it cost you? You decide now.

The other risk is way down the road, and then you may face things that your successors will feel obligated to do, even though the contract doesn't call for it. They may not be so terrible, if worse comes to worse, and if it turns out to be only a short holding operation. But, these are risks.

CHAIRMAN MILES:

You're talking about another set of risks if everything goes, and then some new unforeseen, or heretofore undiscussed, problems (indisc.). What does.... Okay, what are some of those that you haven't yet discussed?

MR. LIPTON:

Well, look....that every step along the line the project looks like it's working out, then the fact you do have off-take contracts. And on the basis of the off-take contracts, commitments are made to finance, whether it's net capital or whether it's equity capital and joint ventures, but commitments are made, because everybody perceives step by step down the line that it's working out. And on that basis, ALPETCO has performed according to the due dates of the contract. But, then, about the time when.... While all of this is going on, other people are making their own investment decisions, too, in similar expectations, and it turns out that, when the first crude oil is being processed, and the first gas oil from the refinery is going into an ethylene operation, and naphtha is being cracked, and products are coming out, all of a sudden you don't have as firm volumes, which changes your average cost of processing, and the prices are somewhat lower than have been anticipated in all of the calculations, because nobody is committing you to a firm price in the future. You are going to have to meet competitive prices, whoever is doing this operation. This could put an on-going operation in a cash bind for some time. And that's not a matter of something unforeseen happening. Everybody who is looking at this is willing to acknowledge that this could happen. These are the

imponderables that happen in the world chemical industry. All I'm saying is that at that point the State of Alaska may be faced with commitments they feel obliged to undertake, which go beyond that of the contract, simply because this is one of your major investment projects in Alaska. And, one way or another, you are not going to allow it to founder for the lack of cash flow.

MR. CHATTERTON:

Then the obvious way to help it out is to reduce the cost of the feedstock.

MR. LIPTON:

Yes. Sure.

MR. CHATTERTON:

Thank you. Mr. Chairman, if I may continue....

This point that you raised earlier of petrochemical plants, etc., even product refineries, "they sort of come in bunches like grapes - they're all built".... The possibility that you pointed out of getting into a cash flow problem after this deal is on-stream, was it in the late fifties or early sixties where there was a situation - as far as I know in Canada and also (indisc.) - with the market for sulfur (indisc.) out of gas?

MR. LIPTON:

Oh, yes....the sulfur problem. Yes....sure. Just let me say this, too. It's not my purpose to put a dark light on this, because none of these things might happen. But, if you've gotten beyond what is the point of no return on the project, you can even, the ALPETCO people or anybody else, foresee problems ahead. But, once you've passed the point of no return, the work having been done, you don't stop the project. One goes ahead.

There is a point at which capital has been committed and construction is going that one goes ahead and completes the project. Look, I don't mean.... I know I sound like.... I don't mean to come here, you know, and preach Doomsday here. It could work out just the opposite way, but my responsibility is to the Legislature, and I feel one of the things I must do is discuss what the uncertainties and what the risks are.

MR. CHATTERTON:

Mr. Chairman, I guess it's just human nature, even though you see if by any chance things look rocky ahead, why you can proceed to build your mind up until you want that (indisc.) as large and as glistening as possible, because that may be the last way to do it right.

MR. LIPTON:

I wasn't really thinking of that. That's probable. But, what I was really thinking was that in an investment process the way in which you evaluate the profitability of an investment decision is always what is the incremental investment and what we will get back from that. And there comes a point when you've sunk so much money that it's not a matter of whether what you've already invested pays out, but it's the incremental investment, and what do we get in return for that.

Of course, the classic story of that, and forgive me for bringing a New York episode into it, but this goes back to the 1930's when one of our most famous public servants, Bob Moses, was at that time - later on he built everything - but, at that time, he was in charge of the New York State Recreation Department, and he decided to build Jones Beach, which has become a monument in due course. He asked for an appropriation for Jones Beach, and there was no way in which the state legislature was going to give him those funds. They gave him the funds which they thought were appropriate. And he took all those funds, and he built the foundation for Jones Beach. Then he said, "Now I've got the foundation - give me the rest of it." This is incremental investment decision-making.

UNIDENTIFIED SPEAKER:

The (indisc.) is alive and well and living in Alaska.

CHAIRMAN MILES:

Can you give us an over-view of how this decision, Mr. Lipton, might relate to the other decisions regarding financing of gas line, gas liquids, the structure in which we might be viewing those various decisions? As you know, we are being asked to participate in - the Northwest Gas Line - make a decision whether to (indisc.). Can you kind of give us your over-view?

MR. LIPTON:

I don't think that your decision on the royalty crude contract ought to be contingent upon what may, or may not, happen on the gas. I think that the probabilities of being able to use gas liquids as the basis for industrial development as an

alternative to this are really not much more exciting. I think probably they are more difficult. I think they are more difficult.

You've got a lot of problems on what you're going to do with your gas, when is it stripped, who's going to strip it, is it (indisc.). These are a lot of very difficult problems. They are too elusive right now to try to come to grips with all of them. I would say that we don't feel that your decision on the royalty crude contract now ought to be conditioned in the probability or improbability of what may happen to the gas liquids.

We have been very excited about what may be done with gas liquids. As you know, for many years we first talked about gas liquids probably being of greater significance to Alaska, per se, than the natural gas itself. It's not as though you are going to be energy-short in Alaska. But when you start looking at the specifics of it and, even what we have mentioned on several occasions, which is thinking small instead of big at Fairbanks, there are a hell of a lot of problems that show up. Now, things may still be done, and there are a lot of permutations and combinations, but I think you would be ill-advised at this stage of the legislative process, or the royalty disposition process, to try to condition your decision on this project in terms of what may, or may not, be done with natural gas.

CHAIRMAN MILES:

Thank you. Mr. Lipton, thank you very much. Do you have any closing remarks?

MR. LIPTON:

No, except to express my appreciation for the courtesy you have extended, and I have enjoyed this conversation very much.

CHAIRMAN MILES:

Thank you very much.

Shall we adjourn until tomorrow night - same time, same place?

SCOMM

#14:10

Alaska State Legislature

POUCH V
JUNEAU, ALASKA 99811
OFFICIAL BUSINESS

TRANSCRIPT OF TESTIMONY OF

PUBLIC REBUTTAL

March 18, 1978

BEFORE THE SPECIAL COMMITTEE ON ROYALTY OIL AND GAS

Committee:

Senators:

Representatives:
Chairman Bill Miles
Al Osterback
Chat Chatterton
Mike Miller

CHAIRMAN MILES:

Okay. We'll call this meeting of the House Special Royalty Oil and Gas meeting to order. I'd like to welcome the people here in Juneau.

At the Committee table we have Vice Chairman of the Committee, Representative Al Osterback, Representative Chat Chatterton, Representative Mike Miller, House Majority Leader, and myself, Bill Miles, Chairman of the Committee.

Very briefly, I'd like to explain to the people in Juneau that we are tele-conferencing this hearing. What that, in essence, does is make the comments from the witnesses and from the Committee members available live and direct to Anchorage, Fairbanks, and Nome. We have similar electronic networks set up to both listen and speak in those areas.

The procedure that will follow today in this tele-conferencing hearing is we will take testimony from the witnesses in Juneau... all the witnesses who desire to make a statement for the benefit of those in Anchorage, Fairbanks, and Nome. I doesn't look like we're going to have too many witnesses. Then we'll go on equal footing into Nome, Fairbanks, and Anchorage taking one witness from each area.

AGO 559423

Perhaps, for the benefit of the people on the other end of these microphones, I'll give just a short recap of what the Committee's done this week. On Monday we held a joint hearing with the Senate Oil and Gas Committee, and the principal witnesses were the ladies and gentlemen representing ALPETCO, the firm with whom the state has a tentative commitment for the sale of royalty oil. On Tuesday we had Commissioner Robert LeResche, the Chief Negotiator for the state, outline his views of the historical aspects of the contract and answer a number of questions relating to certain aspects of the contract. On Wednesday a Legislative Consultant, Milton Lipton, who is Vice President of Walter Levy (indisc.) & Associates, spent the evening with us discussing various aspects of world, national, and state economy, if you like to call it that... and again answering questions about the specific contract and the concept of the proposed contract. Thursday evening we had a marathon session that lasted from seven until eleven in the evening with Legislative Consultants from Battelle Northwest who discussed the issue of the state taking its royalty oil in kind as opposed to the state taking its royalty oil in value. Following Mr. Swift and Mr. Clummett (indisc.) from Battelle, we had Dr. Arlon Tussing, of the University of Alaska, speak to a number of issues related to the sale of royalty oil.

That essentially brings us to today's hearing because, in our unusual wisdom, we decided to take St. Patrick's night off, and I'd like to clear with Anchorage and Fairbanks that I went to bed at eight o'clock. It was a very disappointing St. Patrick's night for me.

Subsequent to this hearing, we intend to go through the specific contractual provisions with the representatives from the Department of Natural Resources, the state's negotiator, as well as representatives from ALPETCO. We also have two outstanding studies that will, hopefully, be in the first part of April. We have (indisc.) specific questions relating to the contract to Battelle Northwest. Additionally, we have a net benefit study in progress by I.S.E.R. at the University of Alaska. Following this week of hearings, we are going to address specific questions, further specific questions, to the principals, both the Department of Natural Resources and the representatives from ALPETCO. Hopefully, we'll be able to get a response within seven to ten days and accumulate all the existing information plus the responses to these questions and the outstanding study and make a decision one way or another on the contract.

One final point before we turn the microphone over to our first witness in Juneau, is, for the record, Dr. Tussing requested that his statement before the Royalty Oil and Gas Advisory Board be included in the record that has been distributed to Committee members and is in the record. Additionally, statements from a Wilson A. Rice and Matthew Berman, Trustees of Alaska and Anchorage,

will be included in the formal record of the hearing. With that in mind, we'll turn the microphone and the floor over to Mr. Honig, Chairman of ALPETCO. Mr. Honig.

MR. HONIG:

Thank you, Mr. Chairman.

Representatives Osterback, Chatterton, and Miller, we appreciate the opportunity of appearing before you again after you've conducted a long week of hearings on the Alaska Petrochemical Company project and its proposal to build a petrochemical facility in Alaska to process Alaska royalty oil.

Most of the testimony we've heard this week addressed the risks involved and the rewards for taking those risks and whether the ALPETCO proposal involves any state subsidy or not. I'd like to address these three subjects briefly in rebuttal, and these subjects are the risks, the rewards, and the subsidies.

First, let's look at the subsidies. One newspaper account said the contract includes provisions for both direct and indirect subsidies for the plant. It said that any direct subsidy in the form of a negotiated reduction in price of oil would have to be approved by the voters. But it said the contract also gives ALPETCO an option on seventy percent of any future royalty oil which might be sold cheaper than Prudhoe Bay oil. These are misleading statements in our opinion. ALPETCO's right to up to seventy percent of other royalty oil is neither a subsidy nor does it give ALPETCO a veto on future competition, as has also been said. This Section 2.3 of the contract merely prevents the state, in the future, from engaging in unfair competition. Once ALPETCO's plant is running, if the state should then decide to sell royalty crude oil to someone else at a lower price than we are bound to pay under the contract, then we have the right to that same lower price for that quantity being offered at a lower price than ours. This is only fair, and it's a customary provision in long-term supply contracts.

Regarding the other so-called direct subsidy, the contract makes it as hard as is possible for ALPETCO to ever reduce the price it will pay the state for the royalty crude. Any reduction of the price provision must be approved first by the Administration, second by the Legislature, and, finally, by a vote of all the voters. I fail to see how either of these provisions can be referred to as subsidies.

As Milton Lipton told you, nothing will fly without a firm quantity. The contract must assure availability, he said. Regarding the contract generally, Mr. Lipton also said it was "carefully drawn, imaginative, and favorable to the state." He told the Committee that it represents maximum effort on the part of ALPETCO and the state. ALPETCO is getting no bargain, he said.

Secondly, a lot has been said this week about risks to the state,

and less has been said about the rewards to the state. Most things in life involve some risks, in the broader sense, and usually we face some trade-off between risk and reward. It would have been safer to have stayed home this morning, but we took the risk of leaving so we could be rewarded with each other's company.

Let's divide risks and rewards into near-term, say the next five years, and long-term, beyond five years. Near-term to risks have been discussed by your consultants. One felt that ALPETCO might flood the California market with crude oil, undercut prices for the oil, and thus lower the average value that Alaska would receive for its royalty oil and severance tax. This scenario, we feel, is extremely remote. ALPETCO cannot take any crude at all on an interim basis until it has long-term financing commitment for a least one-and-a-half billion dollars and it has at least seventy percent of the plant output under long-term contracts before we can take any crude on an interim basis.

Besides, ALPETCO cannot borrow money to finance interim crude purchases from our banks unless it is already under contract for sale and for sale at a profit. So, it's difficult to see how this is probable at all. The only other near-term risk I recall being mentioned is that ALPETCO might be unable to put the project together within the next eighteen months. This is certainly possible. We cannot guarantee the project will fly, but we're betting several years of effort and at least ten million dollars that it will fly in that eighteen-month period. Suppose it doesn't. On the down side, maybe two years have gone by and Alaska is still without a plant. There is no project, but the state still has its oil and it has spent no money. Where is the risk, then, except for ALPETCO's loss? Some of your consultants have said such a two-year delay might be a plus for the state. The markets may be better by then. So, there's no risk here for the State of Alaska.

On the other hand, what are the near-term rewards? There are two big ones. One is employment and the other is contracting work for Alaskans. During the five-year construction period it is estimated that the construction jobs in Alaska will approximate four thousand employees. The total construction man hours in Alaska is estimated by engineers by over thirty-four million man hours spent in Alaska. Additionally, ALPETCO will make the maximum use of local sub-contracting and local supply firms. Add to these the support jobs and the indirect services, and the near-term rewards are immense.

But the long-term risks and the long-term rewards are the most important. What are these? The worst long-term risk mentioned by your consultants is that the plant will be built and running, perhaps for several years, the one-and-a-half to two-and-a-half billion dollars will have been invested, and then the economy sours, or the petrochemical industry sags, or the big companies somehow squeeze

AGO 559426

ALPETCO so that ALPETCO starts losing money and has to shut the plant down. This could happen. It's possible. It can happen no matter how big the company is that owns a petrochemical plant or any other kind of plant, for that matter. But this is not a function of the contract plans proposed. It is a fact of life; a risk we take in pursuit of greater rewards. It's not too probable in ALPETCO's case that that will happen, because for ALPETCO to get financing, it must prove to the lenders that this risk is minimal. But, suppose the completed petrochemical plant does fall on hard times. The State of Alaska takes back its crude oil, in that event. It does not have to give ALPETCO anything. It does not have to lower the price on the oil.... that's up to you. If bad times occur, then at that time, not now, you, the Legislature, the administrative part of the government, must make a decision. Do nothing, and get your oil back, or work with a new owner to operate the plant. But, if you want to lower the price; that is, pay for the crude, then the voters must also approve it after you have approved it. Whatever the risk is to ALPETCO, ALPETCO is willing to take it. We're not newcomers to Alaska. We've taken risks in Alaska before, because we believed in the future of the State.

In 1959 we took a risk in Alaska. We invested sixteen million dollars. It doesn't sound like much today, but it was an awful lot...amount of money then. We invested it in a natural gas pipeline distribution system for Anchorage. This was long before Prudhoe Bay, long before high fuel prices. That project...that investment was so risky that in order to borrow the money we had to get the oil companies who were willing to sell us the gas to co-sign our notes. We didn't have any customers at all to begin with. But, we had faith in the growth of Alaska. We had faith in that project. We took a risk, and we've enjoyed the reward... so have the people of Anchorage and so have the people of Alaska.

This contract is a good contract for Alaskans. It creates permanent jobs...almost three thousand permanent jobs. It creates a large, additional tax base; approximately forty-nine million a year in today's dollars. It creates an investment for almost thirty-five thousand Alaskans to participate in the affairs and the profits of the company. It also provides profits to be shared in an endowment trust for the benefit of Alaska. As Mr. Lipton said, if it comes to fruition, this project has many advantages to the State. Even Arnold Tussing said, it will benefit Alaska if ALPETCO can put it all together. What we ask of you is the opportunity to try. Thank you, Mr. Chairman.

CHAIRMAN MILES:

Thank you very much, Mr. Honig. Questions from the Committee?

I have a comment on the point about subsidy, and we seem to have

AGO 558427

gone 'round and 'round on this before. You stated that this is neither a subsidy nor a veto over future contracts, or words to that (indisc.). I still have a tendency to disagree with you on that. There are clauses in the contract which state that we have to build a (indisc.) tank. I think that one of your consultants priced that at roughly at nine million dollars, and it won't get paid for that until the termination of the contract twenty-seven years down the pike. To me that appears to be a subsidy.

Additionally, there is a specific clause in the contract, and I believe you referred to it, about the...if there is a price change, the Administration, the Legislatore, and the voters have to ratify that. Well, the very existence of that clause indicates that in the future there may be a request for a less than in-value price change or reduction of price change. I think we've both discussed this. I'd just like to have those comments on the record, and you are certainly free to respond, Mr. Honig, but....

MR. HONIG:

I'd like to make a comment on each of them, if I may.

CHAIRMAN MILES:

Certainly, Sir.

MR. HONIG:

With respect to (indisc.), I suppose that could be viewed as a subsidy. Actually, the agreement provides that we will repay the State the value of that pack at the end of the contract and at end-of-contract values on crude. So, I really think it's more of an investment of nine million dollars, if you want to look at it that way, than it is anything else.

CHAIRMAN MILES:

Well, you could look at it that way or as a subsidy for twenty-seven years.

MR. HONIG:

Yes, I suppose you can look at it either way. It was considered I think by most as one of the nits in the many, many months of negotiation. It is a lot of money, but it is not a lot of money relative to the amounts we are talking about in the contract.

On the second point about the provision in the contract that any price change must also be...any lowering of price must be voted on by the voters, as you've been told, I believe, earlier this week this provision was insisted on by the Governor, and I think it is significant because, if there were no such provision at all

AGO 559428

in the contract, if the contract were silent on any provision of price, then, as we all know, ALPETCO and the Administration and the Legislature could agree on any term outside of the contract by mutual consent and could modify the contract by mutual consent without every going to the public for a vote. So, the fact that the clause is in there certainly doesn't weaken the contract. It simply says that ALPETCO and the Administration and the Legislature cannot get together and agree on a price reduction unless and until the people vote on it and also approve it. So, I think it's a strength and not a weakness because, as I said, absent that provision, it would be easier to modify the price downward.

CHAIRMAN MILES:

My point in raising the voter approval is not to say whether it's a good idea or a bad idea, it's just to make very clear that the parties to the negotiation, the Administration and ALPETCO, were cognizant to the fact that this request for price reduction is an important part of the contract and that they were very aware of it and that it's a very real possibility. That's the point that I would like to make.

Questions from the...Representative Chatterton.

MR. CHATTERTON:

Thank you, Mr. Chairman.

Mr. Honig, I have in front of me here what is numbered page five of the flash cards that you presented the middle of last week in your direct testimony in support of this deal. The title of it is No Risk to Alaska Performance Bench Marks. I have, since that time, gone through the contract sort of very rapidly, and I could not find there...and I wondered, with reference to that list, at what bench mark, in time, or performance, or commitment do you earn the right to take all or part of the state's royalty oil. When do you qualify to do that?

MR. HONIG:

We qualify to do that after we have obtained a permanent financing commitment for at least one-and-a-half billion dollars. And we cannot take any oil from the state until we have obtained that commitment, written commitment for financing, and have furnished the state with a copy of that commitment.

MR. PRATT:

Mr. Chatterton, specific reference is made to Article 10.2, subsection D...it's on page 32 of the contract.

AGO 559429

MR. CHATTERTON:

All right. As I have said, I have gone through this and I could not see in Article 10.2, subsection D, A, B. C, or on, up through H.

MR. PRATT:

All right. May I take you to page 6? Mr. Chairman, I'm Henry Pratt, for the record...also with ALPETCO. Article 2.2, Initiation of First Delivery, the first sentence says...After the date Buyer has obtained the financing commitment referred to in Article 10.2(3)(d)... So, if you go back to 10.2(3)(d), that's within the eighteen months after the effective date, and (d) is obtain or cause contractually bound third parties to obtain written commitments to lend or invest at least one-and-a-half billion dollars.

MR. CHATTERTON:

In other words, all you have... If I understand, then, all you have to have is a showing that you have people willing to loan you up to 1.5 billion dollars. Is that right?

MR. HONIG:

That is correct; plus the things that would be necessitated in order to get such a written commitment. No lender is going to give a written commitment to lend us or anyone else that much money or less than that much money unless he's sure that he can be repaid, and unless he's as sure as he can be that he will be paid the interest as well as be repaid the principal. So, as we...as our bankers and investment bankers testified earlier this week, they are willing to commit the financing on this project provided we have it put together. And put together means provided we have, in addition to the long-term contract with the state, ratified by the Legislature, we must have contracts to sell the products over a long period of time in order for the lenders to be as sure as they can be that they will be repaid. So, when you get the financing commitment, it says a lot of things, and it provides a lot of security I would think for the state, because the lenders are pretty hard-boiled about lending money.

MR. CHATTERTON:

Mr. Chairman, if I may continue.

Thank you for that. I understand what you say, but you are under the understanding and the state is under the understanding that once you have the showing, the finance ability, the borrowing ability of one-and-a-half billion dollars, why you then have... and under the terms of the contract...the right to take all or

part of 150 million...150 thousand barrels a day of royalty oil. Is that correct?

MR. HONIG:

Not quite. I think that it's not only the borrowing capability but we must have a written commitment by lenders to lend us that money. Our capabilities could be one thing, but this requires a commitment that we could borrow the money for this project.

MR. CHATTERTON:

All right. You have here....let's go out here eighteen months into the future and you come to our Commissioner of Natural Resources, and there is the Melon or the Hunt Estate, or something like that, says yes; they are willing to proceed to loan you one-and-a-half billion dollars for the purpose of constructing a plant. Now you would say that the Commissioner would look at that and say, here is a bona fide offer to loan one-and-a-half billion dollars. Right?

MR. HONIG:

To build a plant...yes.

MR. CHATTERTON:

To build a plant.

MR. HONIG:

Right.

MR. CHATTERTON:

And, having made that choice with that instrument, you then would say the contract entitles you to start purchasing up to 150 thousand barrels a day of royalty oil. Right?

MR. HONIG:

Right.

MR. CHATTERTON:

Very good. Now, does that have any guarantee, that in itself, that you are ever going to build a plant?

MR. HONIG:

Yes, I think it does, because, like any contract, you can't read any one phrase out of context, and if we proceed with the bench marks, which you referred to, in the contract, and as outlined

on page 5 of the presentation to the Committee, at that same time, which eighteen months after the contract has been ratified by the Legislature, we must within the eighteen months not only get the financing commitment referred to but we must also have committed to spend ten million dollars, we must have contracts to sell at least seventy percent of the output, we must have completed our environmental impact assessment, we must have filed for permits, and we must have finalized the plant design. Then, beyond the eighteen months, let's say we've done all those things, there's still no plant built, obviously, we have subsequent bench marks provided for in the contract which require us not only to report at intervals to the state on our progress but also to do certain...commit certain acts during the ensuing months. And the next bench mark is at the end of twenty-four months. And it says we must have committed at least one-hundred million dollars, and at thirty months we must have commenced construction. Now, if we fail to do that, then the state has the right to cancel our contract, to terminate our contract, and take the oil back if we've been taking any at all at that time. And the bench marks go on up to seventy-two months, at which time we must have committed at least one-and-a-half billion dollars.

MR. CHATTERTON:

Thank you. Mr. Chairman, if I may continue. Correct.

On page 33 of the contract...it's under 10.2(3)...I can't keep up with myself...but it says within thirty months you shall commence construction of the petrochemical facility.

MR. HONIG:

Yes.

MR. CHATTERTON:

And, I'm not quite sure what that facility is. I would have no question but what for you to continue and, under this contract, you would have had by that time to commence construction of the core refinery unit, which, basically, is to handle...gives you a product slate. There's no question about that. Beyond, other than that point, I see nothing other than the continual commitment of money to the project. Nothing about that it has to be constructed, or completed, or anything.

MR. HONIG:

Well, there is nothing in the contract that I recall that specifically sets forth the exact configuration of the plant. That was discussed; it was considered. It was agreed by all that would be probably unnecessarily restrictive and would not accomplish for the State of Alaska what it was interested in accomplishing.

And that was to process the crude oil in-state and to add value in-state. And, so, to say exactly how many towers the plant would have or any other details of the configuration was deemed to be unnecessary. And, money talks and for us to invest at least one-and-a-half billion dollars in a plant, in a facility, means that we'd better be able to process something.

MR. CHATTERTON:

Thank you. Mr. Chairman, if I may continue.

I realize we are all honorable men, but I'm not sure that we will be here five years from now. And, I'll be quite frank with you, I'm paranoid...but they tell me that paranoia is the mother of discretion many times...and so we proceed. Now, in quick summary, in eighteen months you have to have a letter from...a letter unequivocably saying that there is a place that is proceeding, willing, at beck and call, to loan you up to 1.5 billion dollars. At the end of thirty months, why you have had to start construction on a core, at least started construction on something. And, as you pointed out, the contract does say that you will have to have about thirty thousand barrels a day ability for in-state sales, as I recall the contract through here. Now, having accomplished all these things up through this point, why you would be in conformance with the contract, you have no question about that.

MR. HONIG:

Right.

MR. CHATTERTON:

All right. Now, in the meantime, you could be taking 150 thousand barrels a day of crude oil.

MR. HONIG:

Once we have the financing commitment.

MR. CHATTERTON:

Once...yes...after the eighteen months period. You triggered that off. And you can be doing this, and you can be doing very well at this, I might add, financially you can be doing very well at this. And you can build a thirty thousand-barrel-a-day refinery, and you still are in compliance, I believe, with the contract. And you can still spend up to 1.5 billion dollars on that whole project. And you haven't gone beyond that. Now, aren't you in compliance with the contract?

MR. HONIG:

Haven't gone beyond what?

MR. CHATTERTON:

The thirty thousand-barrel-a-day feedstock products refinery and taking 150 thousand barrels a day of oil.

MR. HONIG:

Well, Mr. Chatterton, you are more familiar with the oil business than I, I'm sure, and if we spend a billion and-a-half dollars and all we have is a refinery to process thirty thousand barrels of fuels a day, I think it will be owned by the bank long before we got that far. Now, as far as intentions are concerned, if I may I'd like to call your attention to...on page 14...to the paragraph 4.21 which says Construction Obligations. As I mentioned, we have to read...we can't take things out of context, and I know you didn't mean to. This says - In consideration of the obligations assumed by each party herein, Buyer will proceed with reasonable diligence to design, construct, start up and thereafter initiate operation of a petrochemical manufacturing facility with fuels refining capacity in the State of Alaska. Such facility shall include facilities for the manufacture of energy fuels, aromatics, olefins and, certainly if you manufacture either of those aromatics or olefins, then you are making petrochemicals, and petrochemical derivatives of such basic feedstocks, and will include "offsite" facilities such as power supply, water supply, port facilities and administration buildings. Final process configuration and production rates of the various products listed above will be determined by (i) marketing considerations based on sales contracts for the products and (ii) process optimization of the overall facility design to produce the desired products in the most effective manner. Variations in process optimization will occur throughout the anticipated life of the facility. Such facilities shall be hereinafter referred to as the "Petrochemical Facility."

MR. CHATTERTON:

Okay. Thank you very much, Sir. Thank you, Mr. Chairman.

CHAIRMAN MILES:

While we're on the cost of the facility, how much will the facility cost?

MR. HONIG:

The rough estimate we have, and it certainly should not be confused as a definitive estimate because, as you know, a definitive estimate cannot be obtained until all the products slate is set and we know exactly what will be made, but the rough estimate that we had made by Brown & (indisc.) is that it would cost approximately 2.5 billion dollars. That includes the offsite facilities

such as the dock, the port facilities, as well as the utility facilities which would be...

CHAIRMAN MILES:

I think there was some confusion a couple of weeks ago about whether it was 2.5 or 1.5. I was confused on it, anyway. I don't know how that happened.

Why wouldn't, if it is 2.5, why wouldn't that expenditure be included in the contract. The contract only states 1.5. And, if we are using these time and expenditure bench marks, which have been very carefully set out in the contract, why wouldn't it go up to 2.5? The reason I ask is that all state revenue estimates that you've provided are based on a two-and-a-half-billion-dollar total project, and we are, by definition in the contract, including the total project costs back to January of '75. But, if the benefits that you cite to the state over the twenty-five or twenty-seven-year period of the contract total 1.3 billion dollars on a two-and-a-half-billion-dollar facility, if, in fact, we don't have a two-and-a-half billion-dollar facility, if we only have a one-and-a-half-billion-dollar facility, our benefits are going to be reduced substantially.

MR. HONIG:

Well, I don't know about the last part of that statement, Mr. Chairman, about the benefits being reduced substantially. There would be some fewer jobs, I suppose, and some smaller tax base, but I don't know whether it would be substantial. In answer to your primary question, there were basically two reasons for not going on and on and on up to the two-and-a-half billion or not making the two-and-half billion required in this time frame. One is that, as Mr. Moore has told the Committee, from Bonner & Moore, that a facility of this size must be phased in. It's impossible to either erect or to start up a refinery of this size and this scale all at once. So it must be done gradually, it must be done in phases. And, for instance, the first phase would be the core refinery which you referred to and, along with that, the required utilities for the larger complex and the port facilities. And the next phase might be an aromatics unit. The next phase might be an olefins unit; the next phase might be another olefins unit, depending upon the contracts for the sale of the product. But, it will have to be phased in, and that was one reason for these numbers.

The other reason for these bench marks being what they are is that in negotiating the contract terms Commissioner LeResche said more than once, do not make the bench marks too optimistic. Set the bench marks so that you, in your own feeling, feel they will be obtainable and that we don't have to go back to the Legislature to revise bench marks. So we hope, I think, to beat all of them

if we can...to do better than what's set forth here. But that was the second reason for making it a billion-and-a-half instead of two-and-a-half. As a matter of fact, when it gets past the eighteen-month bench mark, if we succeed in...as we and the consultant refer to it...when we succeed in putting it all together, which means we have the sale of the products in long-term contracts. We'll have the design finished. We'll know what we are going to make more particularly. And we have the financing commitment. When all those things are done. From then on the likelihood of it not going forward is very remote because, as I mentioned earlier, the lenders, the life insurance companies who buy the long-term bonds and commit to buy the bonds, are going to be sure that we have the proper engineers, that we have the proper design, that we can sell the products, that we can make the products we're going to sell, and that we'll be able to repay the debt.

CHAIRMAN MILES:

I see. I think you can understand my concern about that, though, because it's a monumental economic decision we're being asked to make and a billion-and-a-half dollars does represent substantial... I think it's substantially less return to the state than two-and-a-half billion dollars. The tax base alone is a substantially smaller figure.

MR. HONIG:

Yes...I can understand that. I think, though, that sometimes all of us can get lost in looking at what's before us, so to speak. And I think we need to back off and realize that the main thing here from the standpoint of the State of Alaska is to add value to products in Alaska. That's the main thing. And when we get into such a detail as the bench marks, while we think they're good to have, they're not the main part of the project. They're just to help us all be sure it goes forward.

For instance, on the natural gas pipeline, I haven't heard any bench marks mentioned. Does it have to spend a certain amount by a certain time? I haven't heard of it if it does. So, I think this contract goes much further than any I've seen. I don't think the Alyeska Pipeline had any bench marks that had to be met by any particular time...any constraints placed on it by the state, that is. So I think...I'm not belittling the bench marks. I think they are excellent. But I think that to quibble about whether it should have been eighteen months, or twenty-four, or one, or one-and-a-half, or two we lose sight of what the main purpose is. And that is to build a petrochemical facility in Alaska to help Alaska.

CHAIRMAN MILES:

Yes. I wasn't quibbling over the six months, but I was quibbling

AGO 559436

over the thing in dollars, and I think I'm damn well justified in doing it.

MR. HONIG:

I didn't mean to infer you were. I think that from what we hear that to build a petrochemical facility, we'll spend far more probably than the two-and-a-half before it's over.

CHAIRMAN MILES:

Representative Chatterton.

MR. CHATTERTON:

Thank you, Mr. Chairman.

Mr. Honig, I didn't have a chance to thank you for reading that Article 4.2.1. It is certainly the intent, it is your intent, I know, there's no question. It's my intent; it's the intent of the State of Alaska. But, remember my paranoia. And we're down thirty-six months down the line now, after this contract has been signed, and you started construction on a core refinery which can handle thirty thousand barrels a day. At the end of eighteen months you already have in hand the letter that says you have bank (indisc.). You are available at the bank to the 1.5 billion dollars. And, so, here we are merrily going along. You're taking 150 thousand barrels each day of royalty oil.

MR. HONIG:

We may be.

MR. CHATTERTON:

You may be or any part of it. You are, or will shortly, be running thirty thousand barrels a day of it through your core refinery on it's completion and the balance, the remaining 120 thousand, or any portion of it, why...in Article 13 of the contract you can be trading or exchanging any place that you so wish. You're the broker for that. You have title to it, and you're the broker for anything over the thirty thousand barrels a day. That is Article 13 I assure you. It's on page 40 of the copy of the contract I have, which is basically a brokerage clause. If you agree.

MR. HONIG:

I'm sorry. What was the question?

MR. CHATTERTON:

It's page 40. Well, I was mentioning this is a brokerage clause;

It's in the contract. It permits you anything over and above the thirty thousand barrels a day that you're running through the inside-Alaskan refinery, you can dispose of it in any way you wish - sell it, trade it, exchange it. And you have a free hand, do you not?

MR. HONIG:

Not in the...to the extent that I think your question implies. Let's go back to what you termed, and what we termed, the core refinery. I think that we may not be communicating too well there, perhaps.

The core refinery referred to is not a thirty thousand barrels-a-day refinery. The thirty thousand barrels a day item is the minimum amount of fuels we agree, Arctic fuels for Alaska, we agreed we would have the facility capable of manufacturing. But the core refinery, if you have the presentation that you referred to earlier that we made to the Committee on Monday, if you'll look at page 21 of that presentation there is a schematic of the petrochemical facility. And you'll see there that it shows refinery, and it shows going into the refinery crude oil, and it shows coming out the things you mentioned - gasoline, diesel jet fuel, heating oil, and fuel oil. But also out of this refinery you will see that this refinery must also feed the aromatics plant, part of which goes to market and part which goes into the olefins plant, and it also must supply the feed separation plant which goes into the olefins plant.

My point being that, yes, we must have started construction of the refinery. But, once the refinery is built, it will have to serve more than just the thirty thousand barrels. It will have to serve the aromatics plant and the olefins plant. And for us to spend, or invest, a billion-and-a-half dollars in the plant... as I said earlier, you may rest assured that to do it and to live with our lenders...we'll have to build more than just a small refinery to make thirty thousand barrels of fuels.

MR. CHATTERTON:

Thank you. There's no question. I understand that you'll build this in modules and you'll build this refinery, and I'm sure you'll build it large enough to run 150 thousand barrels a day through it. And, until you have the satellite plants, the aromatics plant, and until you have the feedstock preparation plant for the olefins plant, why you're going to ship the bottoms out. They're going to go south someplace. It's obvious. And the products are only going to be used in Alaska to the extent the products can go south.

But, this is the point I'm really trying to get to that bothers me a little bit is...you are, at least at this point, and as I

see this contract, we have a....and there is no economic incentive despite the border-plate language that our intent is to build. But, right now, there is no economic incentive for you to proceed with putting an olefins plant in or an aromatics plant. You are brokering the oil...

MR. HONIG:

I don't agree.

MR. CHATTERTON:

...you are making the products, and I come to the point that the breach of contract clause seems very weak. To me, I'm no attorney, but to me the state is not suffering any economic loss. I'm hard-pressed to see how the state could ever break this contract.

MR. HONIG:

Well, I think that the point I disagree with you on is the statement about economic requirements, or economic incentive I believe is the term you use. There is every economic incentive for us to build the olefins plant and to build the aromatics plant. You may recall from Chem System's presentation, one of their charts showed the projected rate of growth for basic petrochemicals as compared to petroleum products. And they show that the growth in petroleum products is going to be far, far less during the next ten, fifteen, twenty years than the growth and the need for petrochemicals.

The other thing that comes into play on economic incentive is the fact that less value is added by a fuels refinery, and we must add more value than that, in our opinion, in order to support this project in Alaska. We feel that to build a fuels refinery in Alaska would be marginal at best. And we would have no interest in doing so - to build a fuels refinery only. Because it's by adding the value that not only do we create more jobs and more tax base in Alaska, but we also create a more valuable product so that we are shipping out of Alaska not something that we've converted from $13.00 a barrel to $17.00 a barrel, or $15.00 a barrel. But we're shipping something out that now has a value of $30.00, $40.00, $50.00 a barrel in the form of petrochemical products. So, this is why our economic incentive parallels Alaska's desire.

MR. CHATTERTON:

Thank you very much, Sir. Thank you, Mr. Chairman.

CHAIRMAN MILES:

On that point about the additional phasing in of various plants... I almost flunked chemistry in high school... The only reason my chemistry prof passed me was that I had to promise him not to take it in college. That's a true story. But are aromatics and olefins solely restricted to crude oil-based processing as a feedstock?

MR. HONIG:

Mr. Chairman, I'd like to preface any answer by almost the same preface you made. I don't think I flunked chemistry but certainly the last time I had it was in high school. I'm not a chemical engineer; I'm not a petrochemical executive. Maybe that's why I'm Chairman of the Board.

CHAIRMAN MILES:

They say that about Legislators.

MR. HONIG:

But, as you know, our Chief Executive Officer is Gordon Cain, who was here earlier this week along with our consultants in the form of Chem System, so I have to preface any answer to say that this will be the blind leading the blind, but I'll try to answer your question with that caveat.

Petrochemicals, I suppose, in the U. S. really got a big start on the Gulf Coast many years ago when natural gas was at give-away prices, and oil companies would build refineries to make gasoline, primarily, and oils that they were interested in. And, kind of a by-product was the gas, which often was flared for too long and is still being flared in parts of the world. And this cheap hydrocarbon, this cheap gas, which, you know, they might pay a nickel in NCF for it at that time, was found to be an excellent cheap feedstock to make ethylene. And so ethylene plants were built. And the ethane in natural gas is still a good feedstock to make ethylene. The only thing that's changed is is that it's no longer cheap and it's no longer plentiful, no longer in over-supply. It's still a good feedstock. However, as I believe Peter Spitz pointed out to the Committee earlier this week, there are petrochemical products which cannot be made from ethylene or from ethane. And to make the full spectrum of petrochemical products, the feedstock must be oil. I think he also pointed out something that many people don't realize, and that is, I think he said that ninety percent of the petrochemical plants today are being fed by crude oil, not natural gas. But that doesn't mean that ethane is not good feedstock; it's an excellent feedstock for ethane, but it won't make all the spectrum of products that crude oil will make.

CHAIRMAN MILES:

Well...okay. Let me try it again, because, if you answered my question, I didn't pick it up. The aromatics plant and the olefins plant, that's a vital part of your plant. Can they be provided feedstock by specifically...from, specifically, crude oil or also gas and, or, gas liquids?

MR. HONIG:

Well, I think that the aromatics can only be made from crude oil. Is that right, Mr. Chatterton? We're in your field more than mine now.

MR. CHATTERTON:

I didn't quite flunk chemistry, but I would say the aromatics' basic feedstock would have to be crude oil and not the gas oils - quote, unquote.

MR. HONIG:

And what about olefins?

MR. CHATTERTON:

Olefins, why that's an unsaturated paraffin which would normally be coming from your gas oils or your methanes, and methanes could be constructed from it. Right.

CHAIRMAN MILES:

Okay. The reason I asked the question is I brought it up once before and didn't feel that there was possibly the strongest language possible which requires the actual processing. And I just wanted to...the actual processing of oil in-state, and I just wanted to find out about that.

MR. HONIG:

Well, if you use the terms olefins or aromatics then you're generally considered to be into petrochemicals.

CHAIRMAN MILES:

Both gas-based and oil-based.

MR. HONIG:

Yes.

CHAIRMAN MILES:

So, that's what you're envisioning then?

MR. HONIG:

Yes. Yes.

CHAIRMAN MILES:

So, that's what you're envisioning, then, is future gas-based petrochemicals and purchase of gas...

MR. HONIG:

No, not necessarily. This refinery is envisioning running on crude oil as a feedstock. And, as Mr. Spitz told the Committee earlier this week, I believe, it would be designed so that it could also use gas liquids if and when any were available also as a feedstock. But it's not...the project is not centered on the use of gas at all or dependent on the use of gas liquids.

CHAIRMAN MILES:

I see.

MR. HONIG:

When you say gas oils that's not the same thing as saying gas liquids.

CHAIRMAN MILES:

I understand that. But, if we can't make olefins with just crude oil, then there at some time has to be...we at least have to look at the purchase of gas and...

MR. HONIG:

No, you can make olefins with just crude oil. You can make olefins with just crude oil.

CHAIRMAN MILES:

Without any gas liquids?

MR. HONIG:

Oh, yes. You can make the whole spectrum of petrochemicals from crude oil. You cannot make the whole spectrum from gas, but you can from crude oil. Crude oil is the broader feedstock.

CHAIRMAN MILES:

Which excludes...when you define crude oil, then you're excluding the methanes, ethanes, propanes, and butanes?

MR. HONIG:

Yes. Yes.

CHAIRMAN MILES:

Okay.

UNIDENTIFIED SPEAKER:

Mr. Chairman, just a very brief question. I realize that you want to get into the tele-conferencing, and people are standing by patiently. If I could, for just a moment, I would like to pursue Mr. Chatterton's paranoia. As the bumper sticker says, just because you're paranoid doesn't mean you're not edgy. But, I really, for a million-and-a-half bucks you're going to see not just a thirty thousand barrel capacity.

Say you were producing 125 thousand...processing 125 thousand barrels a day. For the entire length of this contract is there anything to keep you from brokering and selling just plain crude oil for twenty-five thousand...for time infinatum?

MR. HONIG:

No, there's not.

UNIDENTIFIED SPEAKER:

So, there's nothing in the contract that absolutely ties down that all the oil that would be sold to your company, even after given a certain amount of even start-up years, would be processed in Alaska. Is that correct?

MR. HONIG:

That is correct, except that, having invested in the facility, it would certainly behoove us to add as much value to as much product as we can in Alaska. And I can't imagine why we would want to broker when we have a facility to make petrochemicals unless petrochemicals, for some reason, fell on hard times. But normally that would also be reflected in the crude oil price. So, I think that it's not likely that we would be brokering crude oil, because we have to pay the state the full price for that, you know...the full price at the time. So there's no windfall here that would cause us to, or tempt us to, want to broker crude oil. As a matter of fact, the only reason that came up in the

first place is that, as you know, one of our present owners is Alaska Consolidated Shipping, and that's the company that a majority of its stock is owned by six regional native corporations in Alaska. And they became interested when they formed the company almost two years ago, I guess. They were interested at that time in trying to buy the crude oil from the state so they could ship it. They were interested in the shipping, primarily. And the other stockholder in Alaska Consolidated Shipping being Sea Train Lines of New York. And so, they wanted to do the shipping and create jobs for the natives and create profits for the corporation, then, in turn, for the stockholders. And they are still interested in shipping now that they're a part of ALPETCO. And the only reason that we asked for interim crude at all was the thought that perhaps we would be able to maybe sell some to the Federal Government to put in the strategic petroleum reserves, or maybe...there are not many probable sales because of the glut on crude on the West Coast. But there might be some that we can't even think of now. And we would be able to, while we were building the refinery, be able to buy and ship, and sell, some of the crude. And that was the only reason for the provision.

UNIDENTIFIED SPEAKER:

One other final question in that direction. I'm not a member of this Committee, and I appreciate very much the courtesy of the Chairman allowing me to sit in today. And I'm...although I've looked over the contract cursorily, I'm not into it in all the detail that the members of the Committee are.

Is there any prohibition against you selling the crude, for instance, to the Orient? I know that the oil companies that are producing and members of the pipeline (indisc.) cannot, but I'm wondering...I don't know whether the state is similarly restricted or, in this case, the person that the state sells the crude to.

MR. HONIG:

My information is we could not.

UNIDENTIFIED SPEAKER:

You could not. Okay, that's what I was curious about.

MR. HONIG:

That is on the "no-no" list for export, I think...currently on the Federal level, and we could not.

UNIDENTIFIED SPEAKER:

I assumed that was the case, but, as I say,...

MR. HONIG:

I think it goes beyond just crude oil. I think we could not sell naphtha; we could not export naphtha out of the U. S., even.

UNIDENTIFIED SPEAKER:

Then, one real...last, final question. Getting back to the point on (indisc. - cough) that you mentioned, which is certainly desirable if those are jobs filled by Alaskans...a little less desirable for jobs filled by Oklahomans...

(LAST PART OF TAPE INDISCERNIBLE - END OF TAPE)

(BEGINNING OF SECOND TAPE)

MR. HONIG:

(First part not recorded.) We started it before we were selected - a training program for both shipping and petroleum operations. And we made arrangements with the International Seafarers Training School at Piney Point, Maryland, to take two natives from Alaska as trainees under the sponsorship of our company. And they are rotated and, when they have finished their training, two more will take their place. We also started two natives training at a refinery in Texas, which is about a thirty-five thousand barrel-a-day refinery owned by Sea Train. And we have two natives training there and they, by the way, are getting very good marks. There are very good reports on them. They are interested, and they're applying themselves, and they're learning. And, while those are token amounts as far as people go, it's a beginning. And we, certainly...our intention is to have extensive training programs for Alaskans and to hire to the extent possible in Alaska.

I think we have another motivation perhaps the pipeline did not have, or any pipeline would not have. And that is that we are building a facility in one spot. It doesn't cover nine-hundred or eight-hundred lineal miles. It's all in one place. And, because of that, the history of these plants, as I think Mr. Norris of Brown & Root testified to the Committee this week, the history of this is that when you build a plant such as this a large percentage of the people who work on building it, various trades, end up continuing as permanent employees to work in the maintenance and the operation of the plant. Because they've helped put it together and they're familiar with it and, therefore, they can help maintain it or help operate it. And I think that I heard a statistic that seems to bear this out the other day, and that was that when Collier Chemical expanded its plant on the Kenai eighty-five percent, I was told, eighty-five percent of the additional employees required were Alaskans, which is certainly, I think, a good statistic.

So we think that for all those reasons because of the native involvement in our company, because of what we want to do, and because of the nature of this animal - the construction being in one place - we think we will be able to realize maximum local hire and do a good job with the training.

UNIDENTIFIED SPEAKER:

Mr. Chairman, may I just offer one comment as an expansion on Mr. Honig's point. This project, we are told by our consultants, and certainly that seems to prove true, cannot afford a high turn-over in personnel. It has to have permanent personnel who are stable. And they've found all over the world that the only stable work force that you can have for a project like this is local people - people who live in the area or people who come from the area of the state that it happens to be in or the country, as the case may be. The transit person has no place in this type of an operation otherwise your operation costs and training just go sky-high.

CHAIRMAN MILES:

Yes, I was thinking primarily of the four thousand construction (indisc.)...

MR. HONIG:

I might mention, in addition to that, we worked very closely with the AFL CIO business agents on this (indisc.) agents in their recent meeting here two weeks ago did endorse the project and the contract, and they (indisc.) to be satisfied with all the terms.

UNIDENTIFIED SPEAKER:

Thank you, Mr. Chairman. Thank you, Mr. Honig.

CHAIRMAN MILES:

Representative Osterback.

MR. OSTERBACK:

May I thank you, Mr. Chairman. Now, I would like either one of you gentlemen to answer a question. What will your products be - diesel fuel, jet fuel, or...?

UNIDENTIFIED SPEAKER:

Yes. For Alaska we would make Arctic diesel, we would make some gasoline, and fuels for use in the state. Outside of the

fuels part, we would make the basic petrochemicals, the aromatics, and the basic olefins. And we would make ethylene, we would make propylene, and we would probably make ethylene glycol, we'd make styrene, and we'd make zylene, probably. And then these basic petrochemicals we would hope to be able to bring in plants in Alaska to take those derivative products and make them into a wider range of petrochemical products.

Where this chain stops, we can't know today. But, as you know, a large host of products are made from the basic petrochemicals.

MR. OSTERBACK:

On your fuel, your gasoline, diesel fuel, jet fuel, would you be distributing that in Alaska?

MR. HONIG:

We have said, in our initial application to the state, that we would not...it was not part of our plan to set up a distribution system in Alaska. We would prefer to make those fuels available to existing distribution systems in the state. So, we would make them and sell them to distributors, probably.

MR. OSTERBACK:

Well, the reason I brought this up... Like our airport in (indisc.) Bay when they were using a lot of fuel there - jet fuel- they would have Norwegian tankers and Dutch tankers come in. Are there some regulations between the different countries where they have to take so much fuel from the Norwegian or the Dutch tankers?

MR. HONIG:

Not to my knowledge.

MR. OSTERBACK:

I could never figure out why they'd come all the way over here, you know, to deliver fuel.

MR. HONIG:

That doesn't make any sense. I don't know of any such regulation. I see no reason why they could not use fuel made in Alaska.

MR. OSTERBACK:

Yes. It seems like it would make it cheaper. Maybe they're getting cheaper fuel from over there. I don't know.

MR. HONIG:

That's a long haul from...

MR. OSTERBACK:

But, they've been coming in there a long time with big tankers. Sometimes we'd have a (indisc.) of tankers. Most of the time it was Norwegian and Dutch tankers.

MR. HONIG:

I see no reason why they couldn't use fuel made in Alaska.

MR. OSTERBACK:

I thank you, Mr. Chairman.

CHAIRMAN MILES:

Mr. Honig, the...I understand that the Department of Environmental Conservation believes an environmental impact statement may be necessary on the project. This is kind of a lengthy procedure; is that going to back you up at all if that requirement comes out?

MR. HONIG:

We hope not, and we will begin immediately on it once the contract is approved. We were hesitant, as were the other applicants, to spend large amounts of money on any phase of the forward movement of the project until the state had made a selection and decided what it was going to do.

CHAIRMAN MILES:

How long might it take in your estimation to (indisc.)?

MR. HONIG:

I think that it would probably take a good portion of the eighteen months that we have to prepare that...to do that. As you know, we have not finally decided on a site even at this point, so it would be impossible to begin that work unless we did it at a number of places until the site selection has been determined.

CHAIRMAN MILES:

Additional questions? Mr. Pratt.

MR. PRATT:

Mr. Chairman, if I just might, with one final remark, call to your

attention the copy that I think we provided the Committee last Monday - Project Information Submitted to the Institute of Social and Economic Research - will perhaps provide Mr. Chatterton and yourself with better insight to the product mix that we anticipate at this particular point in time. The income statement shows the breakdowns of the olefins, the aromatics, and the fuels. And I think may very well provide you with some of the information you were curious about.

MR. CHATTERTON:

Mr. Chairman. Thank you, Mr. Pratt. I do recall the rather illuminous reports that you have filed along about, I think, October 15th or so, and if you haven't materially changed your product mix, why, I suspect I know a little about what it is. Thank you.

CHAIRMAN MILES:

Are there additional questions from Committee members? If not, it's the Chair's intention to call a five minute recess, and give Mr. Honig a chance to get a glass of water. And I suspect we may have some questions, Mr. Honig, from Anchorage, Fairbanks, and Nome if you could stay around to respond to any statements. It would be helpful.

MR. HONIG:

Be very glad to.

CHAIRMAN MILES:

Are there other witnesses in Juneau that would like to make a statement? Okay. As there are none, I would ask Carol, and April, and Myrtle in Anchorage, Fairbanks, and Nome to stand-by. We are going to take a very short break and will be back and will begin testimony in Fairbanks. We will go to Nome to see if Miss Johnson has any witnesses and then to Anchorage.

It's the intent to take one witness from each of the areas until all witnesses have been heard. So, again, we will start in Fairbanks, take one witness from Nome, and then one from Anchorage. And right now we will take a very short break.

(RETURN FROM BREAK)

CHAIRMAN MILES:

We will call this meeting of the House Royalty Oil and Gas Committee back to order. It's my understanding that there are two witnesses to testify in Fairbanks and one in Anchorage. It's also my understanding that the Fairbanks witnesses have delayed

attending other meetings to present testimony to the Committee. If there is no objection from Anchorage, I would like to proceed with taking both the Fairbanks witnesses, contrary to what we said before, because they are in a hurry to get to other meetings. Is there any problem in Anchorage, Miss Dickinson (ph)?

MISS DICKINSON (ph):

There'll be no problem, Mr. Chairman. It'll be fine.

CHAIRMAN MILES:

Thank you very much. That being the case, we'll now go to April Moore in Fairbanks with her witnesses.

Miss Moore, if you could, could you give us a count from one to ten so we could adjust our volume here in Juneau?

MISS MOORE:

Mr. Chairman, one, two, three, four, five, six, seven, eight, nine, ten.

Our first witness will be Dr. William Wood, and I'm going to ask him to introduce himself to you at this time.

CHAIRMAN MILES:

Thank you very much. Dr. Wood.

DR. WOOD:

I've just been waiting here, but not patiently, for about an hour and three-quarters. This is a Saturday in Fairbanks with bright, blue skies, and full of sunshine, and the North American Sled Dog Championship, and the Winter Carnival, and I don't know what all else goes on.

CHAIRMAN MILES:

Be glad you have sunshine, Dr. Wood.

DR. WOOD:

(Indisc.), if that's what you were requesting. I am (indisc.) the President Emeritus, University of Alaska. I have read the preliminary ALPETCO proposal with the late John Barber, discussed the details with the Fairbanks Industrial Development Board last summer. I have read the revised and the standard proposal now up for final consideration by the State Legislature. I have examined in depth the rationale behind the ALPETCO proposal and applaud it. I have studied the outline of the contract negotiated

by the State Royalty Oil and Gas Board. I have not had an opportunity to examine the final contract wording. It's up to the elected representatives of the people of Alaska to do just that.

State Government represents the residents of Alaska. Industry represents stockholder residents of Alaska and elsewhere. Both represent people. The ALPETCO proposal recognizes this fact by showing interest in and concern for people; in particular, the people who choose to reside in Alaska. It states, without fanfare, the advantages to Alaskans of making use of the human value-added concept. What's more (indisc.) in presenting the case where opportunities provided Alaskans by the petrochemical project is not just to earn a living but for the satisfaction of using one's enthusiasm, energy, skill, knowledge, and creatability to good purpose.

The proposed petrochemical project would create nearly three throusand very desirable jobs directly and about seven thousand to nine thousand as secondary and tertiary spin-off, or supporting, services jobs. These jobs are badly needed in Alaska if our present crop of high school and university students are going to have a fair chance to continue to live in this state. I'm particularly aware of this point as I've just spent the week on a project visiting each of the five high schools in this area to talk with juniors and seniors concerning their career plans. This is part of a local Rotary Club project.

In addition to the jobs I have mentioned, there are also those unknown (indisc.) government jobs, both the necessary and the unnecessary, that will undoubtedly come about as a result of the project. The taxes, local and state, to be derived from the project would be substantial. It would make possible social, educational, and cultural improvements that likely could not be accomplished otherwise.

The day is past when Alaskans can rely upon the fond, but futile, hope that someone will come along to do something nice for us someday. ALPETCO shows concern for Alaskans by proposing to establish in Alaska endowment trust - a charitable trust fund to improve its social, educational, cultural, and environmental conditions in Alaska. This is a generous proposal, and most companies don't make this. You have to go and ask them for contributions to various items of this sort.

The risks to Alaska in processing natural resources in the state, when you gain the tremendous rewards for applying the valued added, are exceedingly minimal, in spite of all the consultants you have heard...exceedingly minimal under the contract that's proposed for approval now by the Legislature. Anyone can find fault with another's proposition. It requires no genius (indisc.), not even very much brain power, and practically no courage. Whether it's one person with an idea and determine to propel that

AGO 559451

idea into good use, it is easy to find a hundred to find fault with a proposal to say it won't work...and a thousand who would sit on their hands and do nothing. Doing nothing with natural and human resources is a way to remain in colonial status forever. The road to serfdom is paved with doing nothing.

I can be a very suspicious old man where big industry, or big government, or big social, do-good causes are involved. On the ALPETCO project I have no reservation of consequence. John Barber was completely convincing in presenting the initial proposal to us. The improved version, now for a decision, is an opportunity Alaskans cannot, in good conscience, afford to miss. The proposal merits the support of Alaska. Thank you very much.

CHAIRMAN MILES:

Thank you very much, Dr. Wood. Your message is certainly quite clear and convincing.

MR. HONIG:

Mr. Chairman, may I make a comment in response to Dr. Wood?

CHAIRMAN MILES:

Mr. Honig, you have the floor, Sir.

MR. HONIG:

Dr. Wood, you mentioned the late John Barber and I know you felt as we do that there was no one who was more dedicated, or determined, or energetic, or enthusiastic than he was about this project. And, you'll be interested to know and we so informed the Committee on Monday that it is our intention to name this refinery in memory of John Barber.

DR. WOOD:

I'm delighted to hear it. He was no one's fool. I don't think this was his idea originally, as he explained it. But, as he worked on it, the idea grew upon him. He saw its possibilities, and he dedicated himself to it. And I admire a man of that caliber.

MR. HONIG:

We all do.

CHAIRMAN MILES:

Dr. Wood, one final comment...Bill Miles speaking. I would like to make you and other Fairbanksans aware of the statement that Bonner & Moore, the consultants on this project, have made concerning

the petrochemical refinery, and I'll quote directly from their report. This is a quote: "If the state were to award a royalty oil contract to a group proposing to build a fuels refinery, then royalty gas could be considered independently. If the state were to award a royalty oil contract proposing to build a petrochemical refinery, then it should be understood that natural gas liquid availability, at the right price, would likely require that the oil project be abandoned or converted to the use of natural gas liquid if that option were within the power of the state." End of quote.

I think that residents of Fairbanks, as actively in pursuit as they seem to be of various options concerning the development of the gas industry, should be aware of that finding by the consultants.

DR. WOOD:

We have a small refinery here at the North Pole; one which is taking care of local needs, and the products come from the refining of the crude, twenty-five to thirty thousand barrels a day, and that will go up, we think. And we're delighted with it, frankly, and we hope that it will continue to be the success it has every promise of being.

Now, we're deeply interested in the gas fuel of petrochemical development in Alaska, and we realize that this is complementary to the development of the petroleum fuel petrochemical plant that is under consideration now. And I don't see that there is any conflict that they'd have to work together. And I don't see where you would have to shut one down once the other one began. I've not found anyone that I've talked with in the petrochemical field that would say that this is so. I've talked with people from Dow and some of the other major petrochemical companies, and that isn't their opinion. I don't (indisc) Bonner & Moore make this statement; perhaps I don't quite understand all of the nuances of what they've written. I've read the statement.

CHAIRMAN MILES:

It's certainly not my intention to debate the issue with you or anyone else, but it is a statement by the consultants and we have a responsibility to take all information into consideration before making that decision. It's a statement which directly affects Fairbanks.

DR. WOOD:

Well, if the project is good for Alaska, it will be good for Fairbanks. I think we are determined to see that that's true.

CHAIRMAN MILES:

Thank you, Doctor. I think our Representative Chatterton would

like to make a statement. Representative Chatterton.

MR. CHATTERTON:

Thank you, Mr. Chairman. Good day, Dr. Bill. How're you doing?

DR. WOOD:

Very fine, Chat...very good.

MR. CHATTERTON:

Dr. Bill, I am sorry that my hopefully searching and not nit-picking questions were causing you to wait impatiently, but let me ask you one question.

DR. WOOD:

(Indisc.) is equal, and we could read your discussion. I wasn't just spending a Saturday afternoon listening to the hearings, I wanted to have something to say in the hearings 'cause that's what I thought the exercise was all about. I must have misunderstood.

MR. CHATTERTON:

That sounds fine. No question in your mind, why, whatever we do down here you want to see it done in the best interest of the people, I guess, of Alaska. Right?

DR. WOOD:

(Indisc.), or we'd change voices.

MR. CHATTERTON:

Sounds great. Have a good day, Dr. Bill.

DR. WOOD:

The same to you, Sir.

CHAIRMAN MILES:

At this time, April, can you bring the second Fairbanks witness forward, please, and ask him or her to state their name for the record?

MISS MOORE:

Mr. Chairman, our next witness will be Mr. Terry Palczer.

MR. PALCZER:

Thank you, Mr. Chairman, and Committee members for the opportunity

AGO 559434

to testify, finally. I, too, have been waiting impatiently but enjoyed Mr. Chatterton's searching comments on the contract.

I will preface specific contract provisions with a few general comments.

CHAIRMAN MILES:

Can you state your name for the record, please, Sir?

MR. PALCZER:

It has taken considerable effort to produce these contracts, particularly the sales price...

CHAIRMAN MILES:

Excuse me. Can you please state your name for the record, please?

MR. PALCZER:

Terry Palczer, Fairbanks, Alaska.

I will preface specific contract provisions with a few general comments. It is (indisc.) the administration has undertaken considerable efforts to produce these contracts, particularly the sales price provision for Legislative consideration. And, for that, the Administration is commended. Public input would have been appreciated in the administration's negotiation stages. It is recognized that this Committee, the (indisc.) Committee, or the Legislature must either approve or disapprove the contract's (indisc.). It is also recognized that an expeditious recommendation by this Committee, (indisc.) Committee, and/or Legislature could be incorporated by the administration, the Royalty Oil & Gas Advisory Board, and ALPETCO with due consideration and speed. With a considerable amount of give and take, and through verbal negotiations, it is unconceivable that the working relationship that exists will expedite any proposed modifications to the contract.

The (indisc.) to specific provisions (indisc.), the following comments were presented. Article 2.2 Initiation of First Delivery recommends that deliveries start concurrently with the operation and production of the first phase of the petrochemical facility. Article 2.4 Buyer Option in the Event Certain Quantities Not Delivered. I question the obligation of future royalty oil by negotiated sales rather than through competitive processes. But also ask, if this provision is included in the ALPETCO contract, that the NPR (ph) contract, North Port Refining (ph) contract, is also strengthened with these guarantees.

Articles 4.2 and 4.3 - Construction Obligations and Production of Energy Fuels for Intrastate Use. I interpret this to mean

AGO 559455

that the minimum requirements are to provide facilities for a thirty thousand-barrels-per-day fuels refinery. I question whether this necessarily obligates ALPETCO into the long-term 1.5 billion-dollar investment.

Article 4.2.2 Siting of Petrochemical Facility recommends a change in the time limit for the Commissioner and ALPETCO to select site. It presently reads that in a succession of (indisc.) each selection has as much as a six months' delay. Specifically, the Commissioner must respond in ninety days on each specific site selection, and ALPETCO, in turn, has another ninety days to respond ad infinitum. There is no time limit in that respect.

Article 4.4 Establishment of a Charitable Foundation. I suggest that the contributions begin upon financing production instead of ten years after production starts. (Indisc.) in the future, potentially in the middle nineties.

Articles 5, 6, 7, 8, and 9. I think that the basic (indisc.) for having accounting procedures appear to be complete. As provided by Article 2.2 and Article 13, ALPETCO could potentially become an oil broker (indisc.) at the citizens of Alaska's expense.

Article 10.2 (10) suggests re-modification. There is too much latitude for delay, plus the opportunity to re-negotiate the terms of Article 10.10...excuse me...Article 10.2. Specifically, if you add up all the time frame that the Commissioner has for planning delays, there are fifty-two months of potential delay in the over-all project. What if the time required for delay potentially happened from (indisc.).

Article 10.3 Termination by Buyer suggests a change to a (indisc.) termination with only two sites selected...that's the present terms... with only two sites selected. This suggests a modification along with 4.2.2. of the considerations previously discussed. This one refers to ALPETCO has the option, terminate its agreement, along with other agreements, after two sites have been turned down by the Commissioner. There is no consideration by the buyer for premature, which I interpret as premature, termination.

Articles 11 through 24 (indisc.) comment except with Article 13 in regards to the offering of oil.

Article 25.2 Local Training suggests that a change be incorporated; that there should be a continual program of local training as job opportunities permit. The natural limitations do not adequately address this program. Potentially, ALPETCO would not have to expend any dollars if outside sources materialize in sufficient quantity.

Finally, I have just a few editorial comments. The contract (indisc.) described is offering no risks (quote-unquote) to the

State of Alaska. I propose that a risk associated with the failure of the added value concept to create benefits to the people of Alaska is of concern. The strengths of the contract are in the oil pricing, billing, and accounting procedures rather than the insuring of no risk of jobs, benefits, etc.

Additional covenants, similar to Article 5.5 Covenant to Aid in Obtaining Governmental Permits to assist in the other (indisc.) of the project - for example, to assist in feasibility financing, to assist in locating a suitable site without trying to find out if there is a site that's (indisc.) a suitable site, to assist in minimizing the risks that do remain - the one of non-performance. I'm concerned that ALPETCO may opt out of the agreement. Essentially, (indisc.) these agreements are (indisc.) to purchase for a more profitable adventure such as petrochemicals and natural gas liquids feedstock. The (indisc.) being buying time by the administration in an election year promoting development and of ALPETCO having an edge in future ventures as described above. (Indisc.) constructive (indisc.), the intent being to strengthen the (indisc.) and ensuring in-state profits of the royalty oil.

Hopefully, the recommendations of this Committee will serve to not necessarily approve the contract, due to scare tactics of some that any modifications will kill the agreement, but to act in the full interests of the people of Alaska. Thank you very much.

CHAIRMAN MILES:

Thank you very much, Mr. Palczer. Are there comments or questions from the Committee?

Thank you very much, April. We certainly appreciate the comments from Fairbanks. As usual, they are to the point, direct, and most interesting and helpful to the Committee deliberation. If there are no further comments from Fairbanks, we will now switch to Carol Dickinson (ph) in Anchorage.

Carol, can you come in, please?

MISS DICKINSON (ph):

Yes, Mr. Chairman. We have just one person wishing to testify, Mr. Jerry McCutcheon.

CHAIRMAN MILES:

Thank you. Mr. McCutcheon, you may have the floor, Sir.

MR. MCCUTCHEON:

For the record, my name is Jerry McCutcheon.

If this is a preliminary hearing to obtain data on the irregularities of the contract negotiations and send it back to the administration, this doesn't make sense. But if this is a hearing in which you are going to say you approve totally, then it's a little (indisc.) from the public to (indisc.).

If we have (indisc.) follow the pattern of another El Paso gas bill, and another Cooke Inlet land swap where the State of Alaska got bilked out of about five billion dollars of minerals. I fail to see why this contract is before the Legislature. I have it on reasonably good authority that the contract is still under negotiation as late as the early part of this week. (indisc.) the contract really doesn't belong (indisc.).

Next, the law says, not just one but many times, the Commissioner must have prior written permission for (indisc.) in the contract. And, if you are going to accept that, it seems to me we should (indisc.) a law, if we shouldn't sit there and say...well, the law doesn't really mean what it says, (indisc.), it means something else because there's a lot of things somewhere else that say something different. I think we should really get the clear intention (indisc. - cough) that read the law. Otherwise, we are going to render our laws and our contract negotiations meaningless, and anyone in the future who (indisc.) Alaska is going to realize that they are not going to be able to negotiate a law, or (indisc.) a transaction, because somebody has probably already gotten the inside track. And, if that happens to be them...it's great, but, if it's not them, why they're going to be out.

There are legal questions over prior written permission and then there's a legal question over the sale of oil from yet undiscovered oil reserves. I won't go into it too far, but you have a staff and I suggest you look at those. And, if you have doubts, then hire an independent expert, one who's really independent, and render an opinion. Not like I've seen some other people (indisc. - cough) on the El Paso contracts where the other consultants were hired to render opinions which were favorable rather than which were more factual and representative than a broad section of opinion might be had in the market place.

I can find no evidence that the Royalty Board addressed a number of various issues that it has supposed to have addressed before approving any contract. I think there's six, or seven, or eight various items that (indisc.). I can find it in none of (indisc.). I don't know whether it can be found in writing as to what determination has been made.

There is substantial evidence that the negotiations were other than an arm's length transaction. The obtaining of a (indisc.) public opinion poll that should publicly be receptive to less than a fair market price for a (indisc.) to promote a plant in Alaska. Then all the participants were told that only fair

market price would be accepted. Well, then, there was one who was encouraged to submit on the basis of being able to go to the public and obtain a reduction. You can be sure they will go to the public. They'd be damned fools if they didn't. (Indisc.) it's a corporate interest once they have started to maximize their return and their yield and (indisc.). You have six regional corporations, I understand, and you have the (indisc.) at which the plant is located, then you have the region where the plant is located, all of which would be affected by the plant. And if a state-wide candidate were to have that many votes in his pocket, he would be unbeatable. But, it's worse than just that. There is no other candidate. It would be a one-man race with no opponent, and millions of dollars would be dumped into the election. And that combination should not be permitted to happen. If you're going to rubber-stamp this contract, at least change that section of the contract so that as much money must be spent in opposing any reduction as is spent for.

The (indisc.) that appears in the contract does not change (indisc.), serves notice (indisc.) the State serves notice, and there is no (indisc.) but it's going to take oil. And, after it serves the notice and the (indisc.) is now beginning to take it on, then a court suit is mounted, and ALPETCO is prevented from taking the oil, and the producers have made other arrangements, are we going to be in the same jackass position that we got into in Anchorage International Airport after the Hammond administration destroyed the prettiest stand of timber in Anchorage to build a runway which is scheduled to be abandoned in 1990? And now the State has brought the proceedings, and we'll probably lose Federal financing for the project.

I think the risk here to the State of Alaska is just far too great to bear. The contract should be returned and no negotiations re-opened. If ALPETCO has really made the best offer, and is sure of itself, it would surely again win the contract. They are not sure, and they know that attending the special (indisc.) at less than arm's length transactions would not...they would not be able to gain those advantages again. At this time, I think giving the same conditions which ALPETCO's got the contract under, I think we'd see far larger and more knowledgeable bidders enter the arena.

Again, I can't see the hurry on the...with this project or this contract. (Indisc.) here (indisc.), I guess we used to call it (indisc.) scouting services, a remark by Fish & Game. Fish & Game seeks to (indisc.) on the selection of a refinery site. The Commissioner of Fish & Game, Ronald (indisc.), has recommended that the State delay for two years the decision on a refinery site for processing Alaska's (indisc.)royalty share of Prudhoe Bay oil. He said the delay would allow the completion of the environmental studies to determine the effect of the refinery's

discharges on the fish. (Indisc.) said he told Commissioner of Natural Rescurces, Herbert (indisc.), in a recent memorandum that the studies are needed to evaluate the potential effects of waste (indisc.) on fisheries and biological productivity of a potential site. The Commissioner of Environmental Conservation, Ernest (indisc.), noted his department would issue such permits for such studies, as (indisc.) opinion will be considered along with those of other agencies as well as the general public. He also said he believed the State selection will be made on criteria other than water (indisc.) if water (indisc.) the issue.

Well, if we're in good company (indisc.), I don't see why we can't take a couple of months off and do this thing right instead of all the (indisc. - cough).

With the letter of financial commitment, I thought of the very kind of letters that came...internal letters that came by the State and the City of Valdez when prospective bidders on land in Valdez... and they are totally meaningless. What they do is they go get a letter and then they go get another letter, which they don't make public, and it tells the bank that they're all sewed up. It's done all the time. And I think you're going to have to get that part of the contract very iron-clad and it's going to have to be under oath and the bank's assurance for committing. It's no trick at all to get those kind of letters of commitment.

Then there's the subject of...that was raised here about flooding (ph) California's oil. California is already flooded with sulfur (indisc.)...sulfur-content oil. And oil wells are already being shut-in.

There is a possibility that Alaska's products, or Alaskan production, may be curtailed (indisc.). The Carter Administration may be forced to relent and allow an oil trade to Japan or Canada. I think Mr. Chatterton probably apprised you more of the situation when the question was raised (indisc.) oil and gas (indisc.).

The trade question, I'm going to open a crack in the door now, raises the question what will happen if the trade is allowed to proceed. Would the so-called enormous profits then inure to ALPETCO, or would they inure to the State? Second, it is my guess that if the Legislature would go to the President and get a concession for the state's royalty oil, and (indisc.) the state's royalty oil, I'd think he'd more than welcome the chance to make the exchange. Or at least...it would help him escape from the situation that is now out on the West Coast or which could ameliorate the growing glut on the West Coast. I wouldn't go to a Congressional delegation. I'd get a consultant like (indisc.) Doscher (ph) who'll (indisc.) a compre-

hensive docket (ph) and (indisc.) delegation from the Legislature to raise the questions of the draft and let them take along their expert.

I would also like to note at this time the Doscher and Dougherty Report which the Legislative Affairs (indisc.) distributing is not the final draft. And I didn't know that until yesterday. (Indisc.) parts of that report (indisc.) the draft (indisc. - fades).

Returning to the contract at hand, I find no indication that a plant with gas liquids was considered versus the plant based upon oil. And, if we're going to be again in the position of where we only have one plant, then shouldn't we take the best one we can and run with that? It is my understanding, and this I just heard again when Mr...Chairman Miles quoted from the Bonner & Moore Report, and that's not my source, that a plant based upon gas liquids would drive a petroleum-based petrochemical plant - if they were both located in Alaska - right to the wall. And, if this is true, and again (indisc.) that they are located in Fairbanks, are we Alaskans going to have to subsidize ALPETCO? Or will the State be willing to.....would the State be willing to subsidize ALPETCO, in this case? Or would ALPETCO, having been on the scene, being given the possibility of a State subsidy, preclude the possibility of a gas liquids plant? I think this becomes important, because we have, at this juncture, an outlet for our royalty oil. While we may not be getting very much for it, far less than was ever anticipated, that is the problem of the Administration and the Legislature. But it is probable. The question about the gas liquids.... We do not have an outlet for our gas liquids at this time. And at what the market might be, I think it's very important, and (indisc.) the Bonner & Moore stage and (indisc.) variety studies, it appears that the shipping of the gas liquids and their shipment to an area such as Fairbanks is still, at this juncture, an economic possibility... with or without a gas line, and I don't think that gas line is ever going to go.

I appreciate Mr. Chatterton's remarks the other day. (Indisc.). This question of having one competitor like ALPETCO and another competitor, say like a plant based on gas liquids, which is un-subsidized, raises the question - should the State of Alaska engage, or allow itself to be engaged in such a manner that it enters the private arena in private enterprise? It (indisc.) to subsidize one competitor against another competitor, of both in the same state? (Indisc.) of gas liquids, but apparently we have another one of the competitors which is interested in this project, and wasn't expected, is about to proceed purchasing oil from the North Slope producers and have built a plant in Valdez. But the State, in view of that, still belongs in the business with the possibility of allowing a subsidy at a later date.... and subsidizing one competitor against another.

We have questionsnot only about possible dishonesty in the way the contract negotiations were handled, we have philantropical questions about possible subsidy and the role of the State as subsidies and I'd like to return now to the question of future reservoirs. It seems to me that it says here supply. Supply means that amount of oil or gas that is reasonably anticipated to be producible and deliverable from (indisc) known reservoirs when a specific time period approved by the board (indisc) this section. If you think and quickly run on your computer, you will find that 150,000 barrels a day for the life of this contract would run to 1.4 billion barrels of oil. Now the operators on Prudhoe Bay despite all their balleyhoo and State of Alaska's administration of Natural Resources balleyhoo, is only (indisc) to produce 6.5 to 7 billion barrels of oil. The royalty share of that is a little something less than 900,000,000 barrels. That means that this potential of another 600,000,000 barrels open here . I'd like to know where it's going to come from. Is it -- there's a total lack of appreciation of what the (indisc) reservoir really amounts to and just how large and big it is. That reservoir is the crown jewel of the western hemisphere is the biggest one we have ever found. There are oil fields that are larger in the western hemisphere than that, but the single reservoir of that kind of oil is not. The probability -- there is no probability that the State of Alaska has found another one on its land. It (indisc) less to do about it and there are other rumors that there might be one under the Arctic Wildlife Range, but that -- concocted by myself and Less Gregg (ph) in Don Young's office about 4 years ago. So I really don't think so. It's just (laughter) (indisc) certain issues. From 1970 to 1976, we only found 2 billion barrels of oil in the United States, that's all. So for the next 7 years we quote (indisc) rate, if all discoveries were to be found in Alaska, we could not reach the requirement for this bill, the one-eighth or 2 billion, Or 250 million barrels and you are still substantial (indisc)

It just doesn't seem to be very real. Even if you projected this on to the necessary amount of decades, that it would take, it literally is committing the State of Alaska to all the oil they get in the future. And I don't think that your -- the State of Alaska is ever going to find enough oil to actually satisfy all the requirements that this contract may imply and probably get -- and for the most probable implications which will occur from it because of the (indisc) go to get a reduced price in opening up the contract negotiations again.

I think I'd better quit at this juncture. Thank you very much.

MR. CHAIRMAN: Thank you very much Mr. McCutcheon. Are there other witnesses Miss Dickinson in Anchorage?

MISS DICKINSON:

No, Mr. Chairman. There are none.

CHAIRMAN MILES:

Well, thank you very much Carol in Anchorage, and April in Fairbanks. We certainly appreciate the time that the witnesses put in the unexpected delay and certainly feel their testimony was valuable and with that we'll sign off on the teleconference portion of this hearing. Thank you again.

UNIDENTIFIED SPEAKER:

Bill, do you have a question for the (indisc) ?

UNIDENTIFIED SPEAKER

There is one question. Where'd she get the idea this contract is still under negotiation?

CHAIRMAN MILES:

Would you like to raise that?

UNIDENTIFIED SPEAKER:

Yeah, why don't you ask that.

CHAIRMAN MILES:

Carol, in Anchorage, are you still there?

MISS DICKINSON:

Yes.

CHAIRMAN MILES:

Yes, there's one question that Representative Chatterton would like to raise, with Mr. McCutcheon. Is he still there?

MISS DICKINSON:

Yes he is.

CHAIRMAN MILES:

Okay. Representative Chatteron.

MR. CHATTERON:

Thank you Mr. Chairman. Jerry, a quick question. You mentioned at the start of your testimony there something about the contract still being under negotiation. As far as I think any of us here understands, why that is negative. We've got a firm thing before us that we're reviewing. I hope there isn't anything

AGO 559463

following. Could you sort of enlarge on that comment please?

MR. MCCUTCHEON:

Well, this is one of those things that I heard from a very reliable source the other day at the Royalty Oil and Gas Board Hearing and I'd rather not go beyond that. You can check it out for yourself. You'll know if all of a sudden you wind up with a slightly different contract in your hand or the best way I suppose is to call the administration before you and ask them. But I'd certainly -- I'm just passing a little heresay information and I'd rather not go beyond that.

MR. CHATTERTON:

Thank you Jerry, very much, I appreciate it.

MR. MCCUTCHEON:

You're welcome.

CHAIRMAN MILES:

Are there other questions for Mr. McCutcheon? Thank you again Mr. McCutcheon and Carol. We appreciate your time and to you also April and the witnesses in Fairbanks.

MISS DICKINSON:

Thank you Mr. Chairman.

CHAIRMAN MILES:

If there's nothing further then to come before this committee, we'll be placing an ajournment motion shortly. Do you have a final comment Mr. Honig.

MR. HONIG:

I think Mr. Pratt may have.

MR. PRATT:

Yes, I've turned this off. Mr. Chairman, if I might, just a very brief statement that I had not intended to give, but I think that it is appropriate. Should this be on or off? I think it's interesting to note that no one in our group and no one in the administration has used any scare tactics and I don't believe there's been any hurry before the legislature, at least not on our part. But I think it is significant to recount somewhat the history of a few items. And unlike the royalty gas contracts

the entire process of sale leading to the resolution before you, has without question been the most thorough over an extended period of time of almost a year, with substantial public participation, administration participation, and legislative participation. The State Energy Policy Committee with you as Chairman, Mr. Miles, and five other members of the legislature began its participation in the royalty oil sale early last fall and continued until January of this year. On December 6 the Energy Policy Committee made 11 contractual recommendations to the Governor. The specific recommendations included 11 different clauses in the contract. In addition you made 6 policy recommendations. All of this input was not available to the negotiation of the gas contracts last year and in addition, the Energy Policy Committee, I believe, adequately kept the members of the Legislature informed on on-going negotiations of the various proposals including the various contract proposals. I personally feel the Legislature should be commended. It was the Legislature last year which directed the role the oil should be taken in kind and it was the Legislature which established the State Energy Policy Committee. For the first time Alaska has a framework for an energy policy plan and for the first time the Legislature has had considerable input into a royalty sale of natural resources.

The royalty oil contract before you between the State of Alaska and Alaska Petrochemical has great potential for the people of this state and the several thousand permanent new jobs and the millions of dollars of tax revenues, the endowment trust and in providing new industrial base of development for the state. All through what we in ALPETCO consider to be a non-subsidized, no risk contract. This Legislature has the unqualified opportunity to be the first in Alaska's history to lay claim to having established the first major industrial base for a stronger and more stable future. I think that with those remarks, I am not urging you into any action. I'm sure that you're going to take a great deal of further consideration. But I do want to remind the committee, and more particularly the public, that the Legislature has been working on this diligently for some time and I'm sure will continue to work on it for some time and I would not like the impression left that you did not know what was going on and nobody else knew what was going on throughout the last 12 months.

Thank you Mr. Chairman.

CHAIRMAN MILES:

Thank you Mr. Pratt. To your statement just a short response. The knowledge that we have with the exception of the formal letter was knowledge gained in hindsight only to the deliberations when Commissioner LeResche would bring myself or other members up to speed it -- insofar as the State Energy Policy Committee was concerned we did represent the 11 formal contractual recommendations to the Governor and Commissioner LeResche, but generally the knowledge we had was after-the-fact and sort of a reporting -- sort of a reporting sampling. I think that's a -- that is important that we record that -- have that response

AGO 559465

recorded.

Are there final comments from committee members? Representative Chatterton.

MR. CHATTERTON:

Thank you Mr. Chairman. I don't know -- trying -- rolling around in my mind protocol here so I think I will address this question to you Henry. Representatives of your clients met with the Governor in Anchorage yesterday. Did they?

MR. PRATT:

At a public meeting? Is that the one you are referring to?

MR. CHATTERTON:

I'm asking you if they met.

MR. PRATT:

Yes.

MR. CHATTERTON:

Was that a public meeting? You led me to a question now.

MR. PRATT:

Yeah, it -- my understanding of it is representatives of our company up here with the Governor yesterday at a pre-planned public meeting on the entire royalty oil contract.

MR. CHATTERTON:

Right.

MR. PRATT:

Fairbanks the day before.

MR. CHATTERTON:

To your knowledge during public or non-public, was there any discussion of modification of the contract that this committee has before it?

MR. PRATT:

I have no understanding or idea of what took place at either meeting other than there were some 60 to 70 people there and that there was a question and answer period.

MR. CHATTERTON:

Would you be willing to find out for me by Monday whether there was any further discussion of any changes in the contract, please?

MR. PRATT:

I'd be very happy to to the extent that I can and perhaps maybe Connie Barlow can also inquire from the administration's point of view.

MR. CHATTERTON:

I'd appreciate it. Thank you. Thank you, Mr. Chairman.

MR. HONIG:

Mr. Chairman, if I were to make a response to that question which has been raised as Chairman of the Board of ALPETCO, I know of no discussions conducted by anyone in ALPETCO or with anyone in the administration with respect to consideration of any change of any sort in the ALPETCO contract, and I think if that had been discussed by ALPETCO respresentatives, I think I would have heard about it.

MR. PRATT:

Mr. Chairman, I'm sorry, I didn't even understand the thrust of Mr. Chatterton's question. I thought you meant that any members of the audience suggest changes to the contract such as Mr. Paulser (ph.) did.

(Simultaneous speech. Indisc.)

MR. PRATT:

I'm sorry, I did not understand your question. I also would like to make one other response and may it in a very serious vein. Mr. McCutcheon of Anchorage made a reference to questions regarding the dishonesty in the way the contract negotiations were handled. I not only resent that comment, but I know of nothing that could even resemble such conduct at any time during the negotiations. Mr. LeResche, in my opinion, and in the opinion, I think, of the other applicants, conducted all of the negotiations on a very high plane and in almost an aloof manner as far as any of the applicants are concerned, and certainly there was never any hint that any of us noticed at any quarter of any dishonesty whatsoever.

CHAIRMAN MILES:

Thank you very much. Any further comments? Then we'll stand adjourned.

1498

1685
1448/7
21

March 18, 1978

House Special Committee on Royalty Oil and Gas

Public Rebuttal

Testimonies, Issuing to Roy Board,
Berman
Bill Rice

ALPETCO - Charles Honig

Risks & rewards & subsidies

I Subsidies - Direct or indirect subsidies

Direct - Lower price

ALPETCO - 23. not subsidy, not veto

Prevents state from unfair competition.

Why should you get lower price? Do you have a L & D surplus capacity?

AGO 559468

Customary in other contracts,
Lipton said: imaginative,

RISKS Near term:

1) Flood W.C. with crude oil
Lower in-value
Can't borrow money from banks if we don't sell
oil at prof.-it

What if not done by 18 mos?
No b.g deal, 2 years many be good for AK

BENEFITS Employment
34 mil man hours

Sub contracts

Long-term risks:
plant built & running, fails,
it could happen to anyone,
not a function of contract

AGO 559469

State doesn't have to do anything, that it doesn't want to.

ARCTIC used to risks.

Endowment trust

Questions:

Miles: Subsidies, $9 million for line & tank fill, At not voided until 27 years.

Voter referendum makes it clear that there may be a request for a price change.

Hon. Q: Will repay state, value on crude, with interest, looked upon as an investment of in $9 m.l.

Miles: or subsidy for 27 years

Hon. Q: Provision, if contract silent on lower price, 3 parties could decide upon price rather than 4. Strengthens contract not weakens it.

Miles: Request is clear, real possibility

Chat: Page 5, Slide presentation,

What benchmark can you take royalty oil,

Honig: After attaining financing ~~equipment~~ commitment for 1.5 billion

10.2. Se

Could 1.5 billion

Contract commits them to certain acts,

Chat: 30 mos, commence construction ~~by~~ of facility by, core refinery, nothing else says plant must be constructed

Honig: No other commitments as to configuration in contract

Chatterton:

AGO 559471

Only required to an instate refinery for 30,000 b/d for in-state.

4.2 aromatics obviously petrochemicals
olefins

$2.5 billion

Miles: Why isn't expenditure included in contract?

All figures based upon $2.5 billion, benefits reduced.

Honig: ~~Small~~ Fewer jobs
Smaller tax base

Pessimistic bench-marks

Gas contract

Chatterton: p. 40 Article 13
Can sell anything in excess of the domestic needs

Honig: 30,000 b/d is not core refinery — large ~~more needed~~ complex needed to making fuel products, if State

AGO 559472

Hovey

Less value added for refinery, marginal fuels.

Shipping out $30-40-50/barrel.

Our economic benefit parallels State's desire.

Niles: Are olefins and aromatics restricted to

Ethane, from natural gas,

Full spectrum of products from oil

90% of plants are oil-based

Rep. Miller: Paranoia,

Nothing says oil will be processed,

But after investment, we would want to ~~make~~ process oil to its highest value for profit.

ACS became interested in building Alaska shipping industry / market crude oil

Ask for interim crude.
For sale to Feds for Strategic

Osterbank: Diesel fuel
Ethylene
Propylene
Styrene
Xylene

Distributing jet fuel, etc in AK
Not required to

Osterbaek:

AGO 559475

Pratt:

I&ER report shows breakdown & idea of products.

Witnesses in Fairbanks:

Dr. William Wood:

Human value-added concept

3000 direct jobs

Risks are minimal in contracts
No genius & no courage to be a wildcatter.

Miles: Reads Bomer & Moore finding that one must be shut down for another.

Wood says no one else has said that.

Miles: State directly affects ~~Alaska~~ Fairbanks

Chart: Hello Dr. Bill

Terry Palazzi:

Public input would have been appreciated ~~by the~~ when negotiated

2.2- Rec. delivery at operation of facility

24. NPR provision Strengthens NPR

4.2.

4.2

2.2.2- Change in time limit, 6 mos for either

Art 13 - Brokerage of oil

10.2 (10) ↑ latitude for delay
52 mos of delay
NOT cumulative

10.3 - Termination by buyer

11-24

BB 25.2- Continual job training

AGO 559477

Risks of failure is of concern

S.S. Aid in determining, locate site

Anchorage: Jerry McCutcheon

Does Commissioner have prior permission to negotiate contract?

Other than an arms-length negotiations, Poll said people would give lower price for $ (subsidy) to develop interest.

ALPETCO not sure of themselves

No hurry

Letter of commitments mean nothing, 2nd letter keeps bank scot free

Dorsche-Doughterty Report — AGO 559478

If we ~~tak~~ must have 1 plant, ~~you~~ have best one.

Gas liquids plant drive ALPETCO's

plant to the wall.

Dishonesty in negotiations

Subsidies

Chatterton: Contract still in negotiation?
Ask administration

Pratt: No scare tactics
Substantial participation, legis, admin & public

Miles: Knowledge gained in hindsight only
from Le Roche - after-the-fact.

Chat: Public meeting w/ Governor and ALYETCO officials.
Any discussion of modification of contract.

Norris: Knows of no changes being considered

Pratt: Didn't understand question

AGO 559479

Hon. Q: Dishonesty in contract negotiations.
Resent such a comment.

SCOMM

#14:11

EXCERPT FROM THE TESTIMONY OF JOE MOORE

April 5, 1978

CHAIRMAN MILES:

Joe, a couple of questions, I think, -- if you could put on your oil consultant hat for a moment. How serious is the possibility that the royalty oil contract will short circuit any gas, any possibilities of in-state gas process?

You seem to indicate that --

MR. MOORE:

Putting it in that sequence, I don't think it would make any difference.

That is if the royalty oil contract is approved and the process goes along, as I assume it will be scheduled to go along. I would estimate that a substantial chemical company, if they could be interested in the utilization of gas for a chemical plant -- I think that they would not consider the royalty oil contract as being inhibitive there. I think they would look at it as a certainty.

CHAIRMAN MILES:

Okay, that's what I don't understand. If there's going to be marketing problems of the two facilities; one facility is essentially substantially less expensive to build, it seems like there's going to be a problem downstream.

MR. MOORE:

Well I guess if you think about the ALPETCO cake as (Indiscernible) as ALPETCC has said, they're not committed to any particular product slate and in order for ALPETCO to build the plan on the scale that they have envisioned, that they have indicated that they would build, they have not built -- their investment schedule envisions building a big petrochemical plant. They could build something that would otherwise meet the state's criteria, having built something significant for a lot less -- see a billion and a half I think is their first cutoff point. Now what that really does, it ties them into building something pretty darn elaborate. (Indisc.) Now to build that petrochemical plant they have got to in some way market this product in a market which they participate. They have to penetrate a market that they're not involved in, that they're not in right now. I suppose that their strategy really would be that this penetration would be through some kind of joint venture. I don't know this, I'm just interpreting what I think I've heard Hugh Spitz and Gordon Cain say, that they would be looking for people who are presently in that market but who would come in as some kind of a joint venture on the

plan with ALPETCO. Now if that were the case, then a joint venture partner would be -- well there would be ARCO, there would be EXXON, it would be SHELL, it would be GULF, it would be CARBIDE, it would be MONSANTO (ph) or it would be DOW. Now I don't think any of those people would go into partners with ALPETCO.

CHAIRMAN MILES:

Where does that leave ALPETCO then? Insofar as proceeding with the contract.

MR. MOORE:

I think to proceed on the full scale that they envision, I think they have real problems as I have said in my report. They may proceed -- they may very well find that nitch that they can proceed on and I think it's fair to say that their thinking is probably pretty wide open on that point. But the project that was proposed originally by John Barbour which I think is the only really written version we have seen with the scope of what the ALPETCO project would be -- I think they can't do that. Now I'm not saying they can't do something, but I don't think they can do that.

CHAIRMAN MILES:

Well what do you envision them doing?

MR. MOORE:

Well it would be feasible for them to build a fuel refinery and a third stage to which they would start adding some petrochemical operations.

CHAIRMAN MILES:

Based on crude oil or --

MR. MOORE:

Yeah, crude oil. I mean let's just take -- forgetting the gas for just a moment, let's just take one of the scenarios which is most likely of success for ALPETCO. Well I think the first criteria will be that the most successful thing they can do would be something that would be simple. And the simplest thing they could do would be something that would be essentially a fuels refinery, a core plant to start with. What's the next simplest thing that they could do? Well probably produce some aromatics. What's the next simplest thing that they could do beyond that -- a few specialty chemicals. Now you're building up to the point that can they at some point develop a position in the

market such that they could competitively go up against the real big companies and force their way into the (indisc.) market. Well with some financial substance behind them, the plant in place, they've got lots -- they've got maybe a chance for doing that. What I have felt was wrong with the plan that they originally proposed was that there was no way that they could go into that market with those big companies and succeed. That those companies would keep them out and in my report I pointed out that in the chemicals business, unlike the fuels business, market share is guarded very carefully by those people who are in the market. And they really fight for market sharing on a competitive basis. And they don't really in the fuel oil business. I mean a few of them do but, you know, fundamentally EXXON and ARCO aren't out fighting for fuel oil business. If somebody wants to sell fuel oil, undercut them $.10 a barrel, fine they'll do something else with their oil, they won't really fight them for it. But in the chemicals business, because of the high profit margin during the good times, they'll fight for their share of the market. And they fight by cutting the price. But ALPETCO is going to run against them. If they start trying to sell ethylene, they're going to run up against a situation where (a) they're unproven suppliers and where they're going to go to is being supplied to somewhere else. Now they're going to be able to woo them away from that alternate supplier either by cutting their price below the price at which their present supplier will cut price and they can't cut the price as low as their present supplier will cut price or they're going to have to (indisc.) say ALPETCO has a -- represents an assurance of future supply, which is better than their alternate supplier and furthermore that they will be willing to pay enough more for that future assured supply since there's the fact that their competitor's going to cut price more than ALPETCO can cut price, will still give them the incentative to come with ALPETCO. But ALPETCO will never be able to cut the price as low as EXXON will cut the price or as ARCO will cut the price or MONSANTO and so forth will cut the price, they just can't do it. So they've got to figure out another way to attract somebody to buy from them. And that's pretty hard to do. When somebody else will cut the price to whatever it takes to keep the business, it's hard to get away from it. And that's the fundamental problem they're going to have.

CHAIRMAN MILES:

Well I'm still unclear as to how that statement relates to what your report says. Liquids availability at the right price would likely require that the oil project be abandoned and converted to the use of NGL (ph). Either it's -- and maybe I'm just making this too black and white, but it seems to me it's going to short circuit NGL development or it's not. I don't get what the balance is or what the ratio is.

MR. MOORE:

Well I don't have a certain answer to the question either. I would say this though that if you had -- let's take ARCO, they're a big ethylene producer and they produce on the North Slope. Now if ARCO decides that it made sense to them to supply the West Coast ethylene market growth with gas liquids, I don't think that ALPETCO's -- the fact that ALPETCO is out there also, would deter them a moment. I think that they could figure that they could kick ALPETCO out of any situation that ALPETCO was in. They've got the financial muscle, the marketing muscle and everything else to do it. If it were the other way around, I think there would be a problem. I think the fundamental issue in the chemicals business is the -- not in the chemical business in general -- but the ethylene business, particularly, is that that is a very big company business. And pretty big companies have been forced out of that business because they didn't have the financial resources. And if you look at people who are in it now. It's nothing but the very largest corporations because it has gotten to require so much capital and willingness to absorb substantial downside risks under poor market conditions. It's just a game that small companies can't play.

CHAIRMAN MILES:

You're not answering my question.

MR. MOORE:

Alright, phrase it again.

CHAIRMAN MILES:

I'm trying to find out how approval of the ALPETCO contract will affect the development of gas or gas liquids in the state? Well that does seem contrary to what you said in your report.

MR. MOORE:

The report -- oh, okay I see what your problem is. If these were two separate activities (a) you had the ALPETCO contract you sign it then (b) you wanted to do something to develop the gas liquids thing. When you sign the ALPETCO contract you have not said that. What you have signed is a contract to develop a petrochemical complex. I think that is a very important understanding.

CHAIRMAN MILES:

Do you want to repeat that last one.

MR. MOORE:

Well ALPETCO has a guarantee it can build a petrochemical complex.

CHAIRMAN MILES:

I just want to make sure I heard you right.

MR. MOORE:

That's what their intention is. And that's what everybody hopes that they're able to do. But it could well turn out that the thing they -- if they put something together it may be something that does not involve a petrochemical complex initially. So that's the first point. You haven't necessarily said you're going to build a -- create a petrochemical complex by ALPETCO. And the second thing is that if you could find someone who is -- if you had a good deal on a gas liquids side, and you really were -- and you had made a policy decision that ALPETCO was the group that you were essentially cooperating with in this kind of development, then you probably would want to give them this favorable opportunity. Now if you did not choose to do that, if you said well, ALPETCO's on their own, you know, the state has no more relationship with them other than just having signed this contract guaranteeing them a supply of royalty crude and now we want to set up a -- want to entice a big chemical company to come into the state and use these gas liquids, I don't think the existence of the ALPETCO contract would deter per se would deter, you know, an ARCO or a DOW to come into here and looking at the gas liquids, if they were otherwise inclined to do so. I just don't think that the ALPETCO contract -- they would weigh it one way or the other.

CHAIRMAN MILES:

Okay. Let me put it this way then. If ALPETCO entered the contract and it's approved, does what it says it's going to do, 30,000 barrels of fuel and the rest in petrochemicals, would you recommend to a major client that they go in and develop a gas liquids facility?

MR. MOORE:

If I was sure that ALPETCO would do that?

CHAIRMAN MILES:

Yeah.

MR. MOORE:

No, I wouldn't.

MR. CHATTERTON:

Is that because the market in other words is full enough now, saturated enough now that one plant might break in but two would be doggone (indisc.)

MR. MOORE:

And so fundamentally I'd just repeat that I think that ALPETCO --I think it's unlikely that ALPETCO in their first realization and what their affect on the market is over the next two years or 18 months or whatever it is, I think it's unlikely that they will really be a factor in the ethylene market or the ability of a major present supplier to promote a new plant. I just don't think they'll be a factor.

MR. CHATTERTON:

If ALPETCO -- if there weren't the strings attached, why ALPETCO was trying to penetrate this market, why would they be in a much more competitive position to do so if the state's royalty share of the oil was transported to California to a petrochemical plant on the West Coast?

MR. MOORE:

Well I think the whole problem -- the point I'm trying to get across is that I see the biggest deterrent as being one that your logic in coming must be that ALPETCO -- you're going to try to keep them out of the market, regardless of their feed stocking, regardless (indisc. -- cough).

MR. CHATTERTON:

But whether it be Valdez, Kenai or the West Coast, that would be under the terms of the contract with the State of Alaska, but there is some other thing where ALPETCO could -- there is permissiveness in the contract where ALPETCO could knock anybody else out of the market.

MR. MOORE:

The contract, yeah, but not in the bank book.

MR. CHATTERTON:

But in the contract why it's permissive -- I mean presupposing they could get their feed stock at $.50 a barrel. They could do a pretty good job, (indisc.). Even if we gave them the oil?

MR. MOORE:

Well I'd say it's in the range of feasible alternatives. I

think that it doesn't help. I don't think that they are particularly helpful one way or the other.

MR. CHATTERTON:

I see, thank you.

MR. MOORE:

We have worked with so many projects where people have tried to break into the ethylene market, people double the size of ALPETCO or even some a little bit bigger and at some point it gets down to the fact that you've got to have lots of guts or your banker's got to have lots of guts to go ahead because there's so many ways that competitors can keep you out of that market and if they're bigger than you are and they want you out of the market at some point you come to a premise that no one you've ever dealt with before has been able to -- you know, they've all backed away. And they may back away for all sorts of reasons. They can't get the financing, they can't get the contracts, so on and so forth. That's just a really rough game.

MR. PARR:

You said something about this a little while ago and I'm afraid I didn't hear you as well as I'd like to. You were talking about in the lower 48 petrochemical plants based on gas liquids hadn't been able to compete whereas this state's position versus (indisc.--loud noise) because of amortization.

MR. MOORE:

Yes, amortization of the total costs.

MR. PARR:

Yeah, and you said that they could absorb, I guess, fluctuations in price, low prices for (indisc.) I wasn't really quite -- I know so little about economics in business that I'm embarrassed but nevertheless I didn't quite understand what it was you were saying. If I understood you right, let's say this plant that ALPETCO's going to have a 2-1/2 million dollar plant, this one might be say a billion dollars, they're both selling the same product, ethylene. Now how does the fact that there's a bigger investment than the ALPETCO plant, I mean assuming that it's one of (indisc.) lower 48 situation, it wouldn't be quite as true up here. But how does that fact that one of them costs twice as much today, help them?

MR. MOORE:

Well, okay. The (indisc.) has two characteristics, one is that it produces a wider range of products and secondly is that of it's total cost, only half of that cost is variable.

MR. PARR:

Their bonded indebtedness or whatever kind it is.

MR. MOORE:

The (indisc. -- simultaneous speech) cost of that plant.

MR. PARR:

That's the same year in and year out (indisc. -- simultaneous speech)

MR. MOORE:

(Indisc. -- simultaneous speech) some costs. But the cash flow that's produced by the plant only has to account for half the total cost which is the feed stocks, utilities and labor support. So if I want to cut the price if I want to compete, you know, cut the price. I can cut my price 50% and still have net dollars coming in every day from the operation of this plant. Now sure, I'm not paying the bank off as fast. Maybe I'm not paying myself back as fast on some investments. But in terms of just the sheer money coming in for the product, less the money going out for the feed stock and the utilities, I can cut prices 50% and still make a positive cash flow.

MR. PARR:

That's if your bank will let you get by with that.

MR. MOORE:

That's right. And then, of course, for that reason, you don't see anybody getting a crude oil plant -- there is no crude oil plant in the word that's not operated by an oil company.

MR. PARR:

So they have (simultaneous speech). The guy that runs the gas liquids plant though doesn't mean they are in the same position, right. There's a higher percentage of his costs are the variables, the cost of the feed stock and so forth.

MR. MOORE:

It could be over-simplifying to say whether it's good or bad. Because I could say well the crude oil plant has more products, therefore it's diversified and therefore that's good. But if you're going into a virgin market, that's bad because you've got to sell so much stuff.

MR. PARR:

So if the price of ethylene is low and the price of something else is high at this time you have a chance to sort of balance it off.

MR. MOORE:

Well if you look at the Gulf Coast where you have all the petrochemical industry there, a crude oil plant that produces all of these byproducts, there's someplace for all of those products to go because there's some plant around there that takes all of these products. Now by contrast, if you look at Saudi Arabia, something you read about in the news, they're looking at several ethylene plants but they're all ethylene plants because there's no plant anywhere around that takes anything. So their marketing problem is very complex and they'd like to just produce one product if they can, based on one product. That's a lot better than selling two products. So in all cases they're looking at the simplest plant that they can come up with so they have the simplest marketing problems; the simplest transportation problems. And this is kind of the analogy that we followed in thinking that the ethylene plant is kind of the obvious one for Alaska because you really have a virgin market. You don't have an infrastructure of other plants around you. And you have to create all that at one time; that means more money, more loose ends you have to pull together.

MR. CHATTERTON:

Well following up on that Joe, suppose we okay the contract with ALPETCO and they go ahead, and they're starting a business -- they're trying to break into the market to produce the products (indisc.) And then if somebody did decide to go into the gas liquids plant, it's going to make ALPETCO's job perhaps even harder because they've got one more competitor who can produce perhaps more cheaply than they can.

MR. MOORE:

Well I think that's true. When you're thinking in terms of ALPETCO trying to build a major petrochemical plant but under the terms of their contract, they don't have to do that.

MR. CHATTERTON:

I understand that. This is just a hypothetical case. Under their contract they have to produce 35,000 barrels of crude (indisc.)

MR. MOORE:

(Indisc.) 100,000.

MR. CHATTERTON:

Billion and a half dollars in a certain period of time or else they lose their contract.

MR. MOORE:

Yes, and that's tough. That's pretty well -- if you really stuck it with that it would tie it to --

MR. CHATTERTON:

A billion and a half is more than you can justify on just producing an amount of fuel oil and gas so they'd have to do something with it or else ...

MR. MOORE:

And personally I think ALPETCO was dumb to have agreed to that. And I think that it is not in the state's interest to hold them to that even. If ALPETCO could come up and show that they had put together a deal for 700 million dollars, 600 million dollars at the end of 18 months, they kept the contract terms and it seems to me inequity that that is a significant affair -- discharge of their obligation. And I look at it, if I were in a position of having to decide whether -- what ALPETCO had done was in conjunction with what the intent of the state was when they started out this royalty oil thing, I'd be hard pressed to say that they could spend 600 million dollars or 700 million dollars on an oil processing facility, that there was anything wrong with that.

MR. CHATTERTON:

(Indisc.)

MR. MOORE:

Well, it is, 600 million dollars is a lot of money.

MR. CHATTERTON:

Not Alaskan terms.

MR. MOORE:

In the refinery and petrochemical industry, it is. I don't

think and I'm not positive of this, but I don't believe that it has yet been grass roots project built for a billion dollars. And you talk about it so much that you almost think it's actually been done. I don't think it's ever been done.

CHAIRMAN MILES:

What's a grass roots project?

MR. MOORE:

Oh when you start off with nothing, just build it. I go out with the grass roots and I create a plant. That's what we call a grass roots plant.

CHAIRMAN MILES:

How do they get them built?

MR. MOORE:

Well they do but there hasn't been one built that big yet.

CHAIRMAN MILES:

They're built in stages.

MR. MOORE:

Well yeah, they're built in stages and also most chemical complexes start off much smaller and so forth. You're talking about something that we've written -- seen so much of the literature about, numbers of this size. And we've almost gotten to assume that these things have really been done, but they haven't been done. Now we talked about billion dollar plants in Saudi Arabia and we talked about even -- well I look at a billion dollar and a half plant in the U. S. They've never gotten built. So we're talking -- you just get kind of hypnotised at the fact that the pipeline cost 8 billion dollars. Yeah, but look who's behind the pipeline.

CHAIRMAN MILES:

What are these 200,000 barrel a day OPEC petrochemical facilities cost?

MR. MOORE:

They haven't been built yet.

CHAIRMAN MILES:

I know, but -- I know they haven't been built yet but --

MR. MOORE:

Billion and a half, 2 billion dollars.

MR. CHATTERTON:

(Indisc.)

CHAIRMAN MILES:

Chat.

MR. CHATTERTON:

Thank you, Mr. Chairman. What's your definition of a petrochemical?

MR. MOORE:

Of a petrochemical from oil, from a hydrocarbic source?

MR. CHATTERTON:

Well if I were to build a petrochemical complex, buy a petrochemical complex and I made this a middle of the barrel fuel product slate, (indisc.) propane, a little butane, wouldn't that be a petrochemical complex?

MR. MOORE:

Well there isn't a legal definition of it.

MR. CHATTERTON:

There is no legal definition, is there?

MR. MOORE:

It's a term of art.

MR. CHATTERTON:

It's a great, broad, wide open (indisc.)

MR. MOORE:

We could probably decide in the sense of it being a term of art. But, you know, a normal person (indisc.) petrochemical complex.

UNIDENTIFIED SPEAKER:

That would make (indisc. -- laughter).

MR. CHATTERTON:

Joe, thank you, you've made a point, I hope. I don't want to admit it.

MR. MOORE:

Any other questions?

MR. PARR:

Tell me one thing and this, again, is an off the top of the head answer. I've got to tell you that this one company came in and discussed with a number of us on this committee, I guess, the possibility of building a strato-plant (ph) over the gas line in Fairbanks and they buy the gas and they put it through a process (indisc.) liquids and (indisc.). It's their responsibility to market the stuff. Is it your off-hand guess that such a thing might be economically viable?

MR. MOORE:

Yeah.

MR. PARR:

Do you have much information (Indisc.).

MR. MOORE:

I think the thing that -- I think that if you just do that by itself, the thing that you probably clearly could do, you could probably recover propane, butane, (indisc.) and sell those. Now that probably wouldn't really contribute anything significant to development in the state if that were your objective.

MR. PARR:

(Indisc.) planned use.

MR. MOORE:

That people would use?

MR. PARR:

Something like the (indisc.--interrupted)

MR. MOORE:

(Indisc.) people.

MR. PARR:

It would be a real big plant.

MR. MOORE:

Oh a hundred people probably.

MR. PARR:

So in terms of an increment of employment or development it's not a real big increment.

CHAIRMAN MILES:

No, it's a term of art, (indisc.) It's a downstream manufacturer is what you'd call it -- the guy who would buy this propylene or whatever it is to make something out of it.

MR. MOORE:

Make something else out of it.

MR. PARR:

And then he came along and located (indisc. -- interrupted)

MR. MOORE:

(Indisc.)

CHAIRMAN MILES:

(Indisc.)

MR. CHATTERTON:

Joe, what's a commercial name for aromatic, one of the aromatics?

MR. MOORE:

Benzine, you mean?

MR. CHATTERTON:

Okay. Let's say the bottoms from the fuel oil refinery would contain those, would it not?

MR. MOORE:

The bottoms from the fuel oil refinery?

MR. CHATTERTON:

Well the tops -- in other words, what you didn't -- if you had products like jet fuel, diesel, stove oil and the rest shifts out why that would have -- what shifts out would have aromatics in those, wouldn't it?

MR. MOORE:

Aromatics are into gasoline (indisc.) If you make these in a plain old refinery, that made gasoline --

MR. CHATTERTON:

I'm not making gasoline.

MR. MOORE:

The aromatics of commerce appear in the gasoline business.

MR. CHATTERTON:

And if I don't take any out why they're still in there, aren't they?

MR. MOORE:

Yeah.

MR. CHATTERTON:

I've separated them from something.

MR. MOORE:

There's lots of aromatics, you know, if you try to be literal but the aromatics of commerce are primarily benzine and secondarily zyalene (ph) and third (indisc. -- noise) and anything else is not really an aromatic of commerce.

MR. CHATTERTON:

And where would our olefins fit into commerce?

MR. MOORE:

If you're not thinking gasoline?

MR. CHATTERTON

No.

MR. MOORE:

Well if you had atomic refinery, you don't have any olefins. Olefins are primarily produced in a refinery by a cracking process (indisc.)

MR. CHATTERTON:

Okay.

MR. MOORE:

Gas, oil.

MR. CHATTERTON:

Alright.

MR. MOORE:

(Indisc.) cracking bottoms or they're produced by thoroughly cracking naptha. In the petrochemical business they're primarily produced in cracking steam, so called steam cracking or steam parolosis (ph) a derivative material producing ethylene and propylene. So that if you had a simple refinery, you normally wouldn't have any olefins (indisc.) If you start producing olefins in a normal refinery you do it because you're making --increasing the octane of gasoline. If you're not making gasoline and you're producing olefins, you're probably producing chemicals like ethylene and propylene.

MR. CHATTERTON:

Okay. Thank you. Thank you, Mr. Chairman.

CHAIRMAN MILES:

Anything else? Joe, thank you very much. You were very, very helpful.

SCOMM

#14:12

SEPTEMBER 1978 STUDY REPORT

VOLUME I - SUMMARY

SALES GAS CONDITIONING FACILITIES PRUDHOE BAY, ALASKA

AMERADA HESS CORPORATION
ATLANTIC RICHFIELD COMPANY - STUDY COORDINATOR
EXXON COMPANY, U.S.A.
GETTY OIL COMPANY
MOBIL OIL CORPORATION
NATURAL GAS CORPORATION OF CALIFORNIA
NORTHERN NATURAL GAS COMPANY
NORTHWEST PIPELINE CORPORATION
PACIFIC INTERSTATE TRANSMISSION COMPANY (ARCTIC)
PANHANDLE EASTERN PIPELINE COMPANY
PHILLIPS PETROLEUM COMPANY
SOHIO PETROLEUM COMPANY
SOUTHERN NATURAL GAS COMPANY
TENNESSEE GAS PIPELINE COMPANY
TEXAS EASTERN TRANSMISSION CORPORATION
TEXAS GAS TRANSMISSION CORPORATION
TRANSCONTINENTAL PIPELINE CORPORATION
UNITED GAS PIPELINE COMPANY

Job No. 5795-1

The Ralph M. Parsons Company
Engineers / Constructors

SALES GAS CONDITIONING FACILITIES STUDY
PRUDHOE BAY, ALASKA

VOLUME I - SUMMARY

TABLE OF CONTENTS

SECTION	TITLE	PAGE
1.	INTRODUCTION	1-1
2.	OVERVIEW OF STUDY RESULTS	2-1
3.	DESIGN BASIS AND CONSIDERATIONS	3-1
4.	PROCESS SELECTION	4-1
5.	PROCESS DESCRIPTION	5-1
	5.1 Inlet Separation and Field Fuel Gas Facilities.	5-1
	5.2 NGL Extraction	5-1
	5.3 CO_2 Removal	5-1
	5.4 Pipeline Gas Compression and Chilling	5-2
	5.5 CO_2 Solvent Regeneration	5-2
	5.6 NGL Fractionation	5-2
	5.7 Fuel Systems	5-3
6	PLANT YIELDS	6-1
7.	PROCESS AUXILIARY SYSTEMS	7-1
8.	FACILITY LOCATION AND ARRANGEMENT	8-1
9.	MODULE FIRE AND SAFETY CONSIDERATIONS	9-1
10.	IMPLEMENTATION PLAN	10-1
	10.1 Schedule	10-1

SECTION		TITLE	PAGE
	10.2	Funding	10-1
	10.3	Procurement	10-2
	10.4	Construction	10-2
	10.5	Logistics	10-3
	10.6	Startup	10-4
11.	ESTIMATED COSTS		11-1
	11.1	Estimating Method	11-1
	11.2	Estimated Costs	11-1
	11.3	Contingency Analysis	11-2
	11.4	Other Facility Costs	11-2
	11.5	Delay Cost Trend	11-2
	11.6	Costs Included in the Estimates	11-2
	11.7	Costs Excluded	11-3
	11.8	Cash Flow	11-4
12.	FUTURE DESIGN CONSIDERATIONS		12-1
	12.1	Basic SELEXOL Process Design	12-1
	12.2	Refrigeration System Optimization	12-1
	12.3	Waste Heat Recovery	12-1
	12.4	Reevaluation of Thermodynamic Data	12-2
	12.5	Pipeline Gas Specifications	12-2
	12.6	Gas Turbine Combustors	12-2
	12.7	SELEXOL Absorber/Stripper Internals	12-2
	12.8	Environmental	12-3

FIGURE

		PAGE
1.	Block Flow Diagram, Sales Gas Conditioning Facilities	
2.	Simplified Process Flow Diagram, Sales Gas Conditioning Facilities	
3.	Site Location Map	
4.	Overall Module Index Plan, Sales Gas Conditioning Facilities	
5.	Sales Gas Conditioning Facilities Implementation Plan Milestone Schedule	
6.	Site Location Plan, Sales Gas Conditioning Facilities	
7.	NGL Extraction & CO_2 Removal Facilities Plot Plan, Sales Gas Conditioning Facilities	
8.	Block Flow Diagram of Product and Fuel Gas Blending	
9.	Sales Gas Conditioning Facilities Pattern of Commitments and Expenditures (Base Case - Full-Capacity Startup)	

TABLES

2-1.	Summary Material Balance	2-3
6-1.	Feed from Gathering Centers and Flow Stations	6-2
6-2.	Pipeline Gas	6-3
6-3.	Fractionator Products	6-4
6-4.	Fuel Streams	6-5
10-1	Manpower Requirements	10-2
11-1	Estimate Summary	11-5
11-2	Crude Oil Cooling Facilities - Unit 62 Estimate Summary	11-6
11-3.	Cumulative Cash Flow	11-7

1. INTRODUCTION

In July, 1977, a group of companies, ultimately eighteen in number, implemented a study by The Ralph M. Parsons Company. The objectives of this Study were to:

- Develop a preliminary design for the Facilities necessary to condition gas produced from the Prudhoe Bay Unit for transmission to the "Lower 48."
- Develop milestone schedules and implementation plans for both a full-capacity startup by July 1, 1983 and a partial-capacity startup by January 1, 1983 with full capacity operation by July 1, 1983.*
- Prepare cost estimate with a plus or minus 20 percent accuracy for these Facilities.
- After appropriate compensation make the Study results available to those parties who ultimately build the Facilities.

In order to accomplish these overall objectives the following major tasks were undertaken:

- Screen the processes available and select a process for carbon dioxide removal and a process for hydrocarbon dewpoint control.
- Develop a process design for conditioning the gas to meet an assumed set of pipeline delivery conditions and quantity and quality specifications.
- Define the auxiliaries and support facilities required for the process plant.
- Prepare equipment data sheets for major equipment.
- Develop a plant layout.
- Identify the permit requirements in the areas of safety, environment and construction.
- Prepare a final report.

The use and availability of the existing first-stage gas injection compressors in the Prudhoe Bay Unit Central Compression Plant to boost the

*At the time this study was implemented the announced startup date for the gas transmission pipeline was January, 1983.

conditioned gas to pipeline pressure of 1440 psig* were assumed as the Study base case. The use of these compression facilities and certain other facilities, owned by the Prudhoe Bay Unit or others, has been assumed in this Study. There is no assurance that these facilities will be available nor have the present owners approved their use. A stand-alone compression plant was considered as an alternate case. The combination of these two compressor options and the two timing options resulted in four different study cases as follows:

- A full-capacity startup July, 1983, assuming use of existing Central Compression Plant first-stage injection compressors to boost gas to pipeline delivery pressure. (Base Case Full Startup.)

- A phased startup, partial capacity in January 1983, full capacity in July, 1983, assuming use of existing Central Compression Plant first-stage injection compressors to boost gas to pipeline delivery pressure. (Base Case Phased Startup.)

- A full-capacity startup in July 1983, using new stand-alone booster compressors to boost to pipeline delivery pressure. (Alternate Case Full Startup.)

- A phased startup, partial capacity in January, 1983, full capacity in July, 1983, using new stand-alone booster compressors to boost to pipeline delivery pressure. (Alternate Case Phased Startup.)

Several important factors which were considered in all aspects of the study included:

- The safety aspects of the Facilities from the point of view of both compliance to applicable regulations and conformance with good engineering practice.

- The continuity of the crude oil production from the Prudhoe Bay Unit.

- The continuity of gas pipeline deliveries.

The results of this study are contained in the following volumes of this report: Volumes II, V, and VI contain confidential SELEXOL® process information. This information has been extracted from distributions to those parties who have not executed a secrecy agreement with Allied Chemical Company.

*At the time the scope of study was defined, this delivery pressure appeared to be a most probable compromise between the economies of higher pressure transmission and the adherence to "proven pipeline technology." It should be noted that the process selected is independent of pipeline pressure within proposed pressure extremes.

VOLUME I - SUMMARY
contains an overview and a summary of the Study.

VOLUME II - FACILITY DESIGN
details the process selection work and design.

VOLUME III - IMPLEMENTATION PLAN AND COST ESTIMATE SUMMARY
presents the plan for design, procurement and construction, and a summary of the cost estimate.

VOLUME IV - APPENDIX 1
provides details on Study scope, schedule, and instructions, and a description of related facilities now located at Prudhoe Bay.

VOLUME V - APPENDIX 2
contains equipment design specifications and data sheets.

VOLUMES VI/VII - FACILITIES COST ESTIMATE, PARTS 1 AND 2
gives the detailed development of the cost estimate.

A detailed Table of Contents for the report is located at the beginning of volumes II through VII. All figures referenced herein are located at the rear of this volume.

2. OVERVIEW OF STUDY RESULTS

The Sales Gas Conditioning Facilities cost estimate was developed with an accuracy of plus or minus 20 percent before contingency was included. This estimate was based on a process design to condition Prudhoe Bay Unit gas to meet an assumed intermediate set of pipeline gas quality and delivery specifications based on the several filings for the proposed pipelines before the United States and Canadian Governments. This gas is sometimes referred to throughout this Report as "sales gas," without regard to the point of sale. The volume of gas available for delivery to the pipeline was as set forth in the Prudhoe Bay Unit Agreement of April, 1977, and in the Field Rules established by the State of Alaska, Division of Oil and Gas Conservation in May, 1977. Assumed study gas delivery and quality specifications were:

Delivery Volume (nominal)	2,000 MMSCFD
Delivery Pressure	1,440 psig
Delivery Temperature (max.)	25°F
Carbon Dioxide Content (max.)	1.0 volume %
Hydrogen Sulfide Content (max.)	1.0 grain/100 SCF
Hydrocarbon Dewpoint (max.)	-10°F @ 1,100 psia
Water Dewpoint (max.)	-35°F @ 1,100 psia

The specified sales gas volume requires a field production rate of 2,600 to 2,800 MMSCFD to account for projected total field and local fuel gas demands (170 to 345 MMSCFD) and shrinkage from gas conditioning (430 to 455 MMSCFD).

The investment requirements for the previously described four cases for the Facilities, including a contingency as determined by risk analysis, are estimated as follows:

	1978 Dollars	Escalated Dollars ('83 dollars)
Base Case Full Start	1,571,500,000	1,962,300,000
Base Case Phased Start	1,581,200,000	1,964,500,000
Alternate Case Full Start	1,688,400,000	2,109,700,000
Alternate Case Phased Start	1,701,700,000	2,107,200,000

A risk analysis was performed to assess the contingency required. In accordance with normal practice in the Engineering Contractor industry, the contingency included in the estimate provides a 90% probability that the project can be completed, as presently designed and scheduled, for the above estimated investment.

The bases and method of preparation for the cost estimate are summarized in Section 11 of this volume.

The process selected for carbon dioxide removal was Allied Chemical's SELEXOL physical solvent process. A mechanical refrigeration process was selected for hydrocarbon dewpoint control. Water dewpoint control is accomplished in the dehydration equipment located in the existing Prudhoe Bay Unit gas/crude oil separation sites called Gathering Centers and Flow Stations. The hydrogen sulfide content of the feed gas is less than maximum specification limit. The hydrogen sulfide removal by the SELEXOL process provides added assurance of meeting this specification. Therefore, it was assumed that no process equipment was required in the Sales Gas Conditioning Facilities for either water dewpoint control or hydrogen sulfide removal.

A Block Flow Diagram, Figure 1, illustrates the basic process flow of the Sales Gas Conditioning Facilities. Feed gas, originating from the gas/crude separators is compressed in the Gathering Centers and Flow Stations and flows to the inlet separation unit. The inlet gas streams are metered, and any solids or free liquids in the gas are removed at this point. The feed gas flows first to the Natural Gas Liquids Extraction section for hydrocarbon dewpoint control. The gas then flows to the SELEXOL section where the carbon dioxide is removed. The conditioned gas then goes to the gas compressors where it is boosted to pipeline pressure, then refrigerated for transmission.

A small portion of the feed gas is fed to the existing Prudhoe Bay Unit Field Fuel Gas Unit. Here a special low water dewpoint and hydrocarbon dewpoint fuel is produced for delivery to the Trans Alaskan Pipeline System to supply certain of its fuel requirements.

SELEXOL solvent characteristically absorbs, along with the carbon dioxide, a significant quantity of hydrocarbons, particularly the heavier hydrocarbons. During the regeneration of the SELEXOL solvent both the carbon dioxide (about 340 MMSCFD) and these hydrocarbons are flashed from the solvent. Thus, the flash gases from the SELEXOL solvent regeneration have a potentially usable fuel content.

To conserve this fuel content of the flash gases, a plan was developed whereby equipment to burn low heating value fuel was utilized in the Sales Gas Conditioning Facilities. Any excess flash gases over local needs would then be utilized in the Prudhoe Bay Unit Facilities after special heating value blending and with field handling precautions. The intermediate pressure (IP) flash gas is compressed and used directly as fuel. The low-pressure flash gas is compressed and fractionated in the Local Fuel Fractionator (LFF) for control of heating value, and the effluent gas is used as fuel. The carbon dioxide in these fuels, which are utilized in the fuel burning equipment, vents in the exhaust at dispersed locations throughout the field.

The hydrocarbon liquids from the NGL Extraction and SELEXOL low-pressure flash gas are separated in the fractionation unit into propane, butanes, and pentanes plus products to facilitate disposal. Some propane is used for heating value control of certain fuel streams. The remaining propane

is injected into the pipeline gas. The butanes are either injected into the pipeline gas up to hydrocarbon dewpoint limits or into the crude oil delivered to the Trans Alaskan Pipeline System. The pentanes-plus are injected into the same crude stream.

It has been assumed that any excess liquid streams and flash gases will be injected into the oil-producing reservoir during the following circumstances:

- Imbalance of supply/demand
- Startup or shutdown
- Equipment outage
- Unit upset
- Other emergencies

A summary material balance is presented in Table 2-1. Sufficient flexibility has been designed into the Sales Gas Conditioning Facilities so that a nominal 2,000 MMSCFD can be produced under virtually all circumstances. The material balance in this table reflects an operation at the maximum anticipated fuel demand for the Prudhoe Bay Unit. It is assumed, though neither assured nor approved, that the Prudhoe Bay Unit will accommodate, at some cost, the high carbon dioxide, high hydrocarbon dewpoint fuel.

Table 2-1. Summary Material Balance

Stream	Volume (MMSCFD)(1)	BPD
Sales Gas (net before any NGL blending)	2000.6	-
Propane (balance over fuel blending)	37.2	24.270
Butanes	41.3	31,290
Pentanes-plus	31.9	28,700
Fuels [approxiimately 50% CO_2](2) 689.0		-
Total Feed	2800.0	

(1) Standard Conditions 14.65 psia and 60°F.

(2) Virtually all the CO_2 removed from the feed gas is reinjected into the fuel streams.

The Facilities require 682,000 total installed horsepower including motors, power recovery units and gas turbines. The bulk of this horsepower is developed by 17 operating gas turbines with 6 spare gas turbines. The flow diagram (Figure 1) shows blocks reflecting the major process and auxiliary systems required. The major auxiliary systems include:

- Refrigeration
- Offsite and general utilities
- Power Generation

A more detailed process flow is shown in Figure 2.

To support the preparation of the estimate at a plus or minus 20 percent accuracy level, the following estimate bases, in addition to the process flow diagrams, were prepared:

- Data sheets for major processes and equipment.
- Detailed plant and support facilities module layout drawings.
- Major piping layout drawings.
- Project implementation plan.

The site location in respect to the entire Prudhoe Bay complex is shown in Figure 3. Figure 4 is a base case design layout of the plant, and also illustrates location of modules for alternate cases and future expansion.

An Implementation Plan provides details for the Facilities funding, design, procurement, fabrication, logistics, and installation.

A full startup of the Sales Gas Conditioning Facilities, by July, 1983, requires strict adherence to the Plan.

A critical timing factor in any construction program at Prudhoe Bay is the "ice window" in the Beaufort Sea. Major plant components can only be delivered via ocean-going barges during the short (4-6 weeks) period each year when the "ice window" is open. Failure to deliver any critical major component during the scheduled period would effectively delay full-capacity startup by one full year.

A milestone schedule for this implementation plan is shown in Figure 5. The critical elements of this schedule include:

- Completion of the process design by January, 1979.
- Timely preparation of all background material, particularly environmental information, necessary to obtain the required permits.

- Long-lead-time equipment to be ordered during the first quarter of 1979.
- Resolution of the impact on and the use of existing facilities at Prudhoe Bay.
- Selection of "Lower 48" fabrication sites.

3. DESIGN BASIS AND CONSIDERATIONS

The Sales Gas Conditioning Facilities preliminary design developed for this Study is based on conditioning gas from the Prudhoe Bay Unit to meet the assumed set of specifications for the pipeline gas as set forth in the Overview (Section 2 of this volume).

The feed gas to the Sales Gas Conditioning Facilities originates from the gas/crude oil separators located in the three Gathering Centers on the West side of the field and the three Flow Stations on the East side of the field. This gas is presently dehydrated in the Gathering Centers and Flow Stations. It was assumed that no further dehydration over current design capability is required to meet the sales gas water dewpoint specification of -35°F @ 1,100 psia. The hydrogen sulfide content of the feed gas is sufficiently low (0.50 grain/100 SCF) so that no hydrogen sulfide removal is required to meet the sales gas specification of 1.0 grain/100 SCF.

For design purposes the feed gas composition was assumed to be that associated with a crude production of 1,500,000 BPD with equal amounts of both crude and feed gas being produced from the East and West sides of the field. The gas composition derived from this crude oil production rate results in a maximum quantity carbon dioxide and NGL feed to the facilities. Lower crude rates would result in increased NGL blending in the pipeline gas and a slightly lower volume of NGL delivered to the Trans Alaskan Pipeline System.

Module and facility layout and design considered the following factors:

- Safety.
- Constraints because of Prudhoe Bay climatic conditions.
- Reliability of operation.
- Ease and economy of construction.

The remoteness and the severe environmental conditions at Prudhoe Bay impose limitations on both the process and mechanical design of the Facilities. The low ambient temperatures (-60°F) and high winds dictate that all equipment be housed in totally enclosed modules for protection of both personnel and equipment. The study assumed the use of safe and efficient methods for Arctic construction used by ARCo., EXXON and SOHIO during development of the Prudhoe Bay Field. Modules with contained equipment are to be fabricated in the "Lower 48." They would be sea-lifted to Prudhoe Bay by ocean-going barges. At Prudhoe Bay they would be offloaded by crawler transportors or rubber-tired vehicles and moved to their pile supports on graveled sites. The pile supports, gravel insulation and an air space below the modules prevent the permafrost from thawing.

Transport by the combination of barge and crawler or rubber-tired vehicles imposes both weight and height limitations on the modules. This in

turn establishes the number of carbon dioxide removal trains at four because of the weight and height limitations for the carbon dioxide absorbers. Weight limitations, to some extent, dictated equipment layout. The use of pile supports plus fully housed equipment made it desirable to minimize plot area or "footprint." Thus, vertical vessels were utilized in preference to horizontal vessels. Equipment is stacked wherever possible to minimize footprint.

The process and mechanical design safety factors adopted were consistent with industry practice and recognized the unique conditions prevailing at Prudhoe Bay.

The reliability philosophy that was adopted for the Facilities was aimed at insuring continuity of pipeline gas flow so as not to adversely affect Prudhoe Bay Unit oil production. Several different approaches were utilized to implement this philosophy:

- The use of a spare parallel train such as the fourth train in the carbon dioxide removal section.
- The use of spare equipment such as pumps and compressors.
- The use of commercially proven technology.
- The use of alternate "handling" such as injection for NGL.

Application of this approach generally led to the selection of conservative processing techniques and proven mechanical equipment.

The safety of personnel and equipment was a major design consideration. The following factors were included:

- Compliance with applicable safety regulations.
- Conformance with good engineering practice.
- Consideration of Prudhoe Bay environment.

Where one design was obviously more economical to install and/or operate than another, the less costly was chosen. In some cases process or equipment selections were made without detailed study because the available economic guidelines did not clearly indicate which was preferable. In some cases additional study of these alternatives has been recommended for the future detailed engineering design phase.

Space was allowed and the major process lines were sized to permit a 50% expansion of the gas conditioning capacity. The allowance included space for both process and auxiliary equipment.

4. PROCESS SELECTION

In July of 1977 a Sponsor Study Team was formed to screen various processes for removal of carbon dioxide (CO_2) from gas produced from the Prudhoe Bay Unit. With the support of The Ralph M. Parsons Company, potentially competitive commercialized processes were evaluated including:

Allied Chemical	SELEXOL®
Fluor	Propylene Carbonate
Shell	SUFINOL®
Union Oil	SORBCO-2®
Lotepro	RECTISOL®
Lurgi	PURISOL®
Open-art	DEA

As the result of this study it was determined that the Lotepro, Lurgi and Open-art DEA processes were not competitive in this application and the Union Oil process did not have adequate commercial experience.

Following this initial evaluation the decision was made by the Sponsor's Technical Advisory Committee to evaluate the Allied Chemical, Fluor and Shell processes in more detail. In addition various processes for hydrocarbon dewpoint control (NGL extraction) were to be screened in combination with the CO_2 extraction processes.

The selection of an NGL extraction process was significantly influenced by the pressure level for CO_2 removal. Three primary schemes were considered:

- NGL extraction at 540 psia by mechanical refrigeration, compression to 1400 psia, followed by CO_2 removal at 1400 psia.
- Compression to 1500-1800 psia, expansion to 1000 psia with NGL extraction by expansion refrigeration, CO_2 removal at 1000 psia, followed by booster compression to pipeline pressure.
- NGL extraction by mechanical refrigeration and CO_2 removal at 540 psia, followed by compression to pipeline pressure.

The last scheme, with both NGL extraction and CO_2 removal at 540 psia, was selected.

Preliminary appraisal of the first scheme appeared attractive since, for both physical and chemical CO_2 removal processes, both the solvent circulation rates and the equipment sizes were smaller at the higher pressures. However, it was found that at high pressure, all of the CO_2 removal processes required more absorption columns because the resulting heavier-walled columns exceeded module transport capacity limitations. Also, the additional operating cost of compressing the CO_2 to high pressure before removal proved to be unattractive. While this scheme made the most efficient use of the existing compressors and minimized solvent circulation it was dropped for the reasons cited.

The second scheme was a compromise to allow efficient use of existing compressors while reducing the CO_2 removal pressure. The number of CO_2 absorbers was reduced, but was still greater than the number required at 540 psia. Additional problems were encountered in the NGL extraction section with this scheme because the hydrocarbon extraction at 1000 psia is much less selective than at lower pressures. This requires the use of two low-temperature deethanizers, resulting in higher operating and capital costs. This scheme also had many of the disadvantages of the first scheme and was dropped.

The final selection of the CO_2 removal process was based on comparative equipment requirements, fuel usage and an approximate module count.

The Sponsor Study Team concluded that, in this application, a physical solvent process is preferred to a chemical solvent process based on the following advantages and disadvantages:

Physical Solvent Advantages

- Less major equipment - potentially lower investment.
- Less process fuel - more Btu's available for delivery to the sales gas pipeline.
- Inherently better extraction of NGL - better selectivity for disposal and pipeline gas blending.
- Dry process and no water required - no additional dehydration.
- No known corrosion problems.
- No special air coolers - no freezing problems.

Physical Solvent Disadvantages

- More rotating equipment (compressors) vs. static equipment (heaters, exchangers, coolers).
- Less flexibility in achieving a fuel balance.

The major disadvantage of the physical solvents involves the desirability of recovering the hydrocarbons in the CO_2 flash gas streams which requires a much greater number of compressors. The compressors, however, are relatively high-volume, low-pressure units which are well within the proven state-of-the-art. The physical solvent regeneration flash gases have a low heating value and must be blended with higher heating value streams to meet the minimum heating value requirements of various fuel streams. The increased operating problems of fuel blending and balance and compressor maintenance were deemed preferable to operating a potentially corrosive and wet SULFINOL system requiring additional dehydration and reboiling and having potential freezing problems. The higher operating costs

for the compressors in the physical solvent system were judged to be more than offset by a greater heating value to the gas pipeline.

The SELEXOL process has the following advantages over the other physical solvent processes:

- Fewer process trains - less major equipment - potentially lower investment.
- No vacuum flash in the regeneration system.
- Better NGL extraction and disposition selectivity for gas or crude blending.
- More potential for optimization.

During the process screening effort it was concluded that the most appropriate method of CO_2 disposal was in the fuel systems. It was assumed that the Prudhoe Bay Unit would accommodate this CO_2 in its fuel.

As a result of these conclusions the Sponsor Study Team recommended to the Technical Advisory Committee:

- That SELEXOL be selected as the carbon dioxide removal process.
- That mechanical refrigeration be used for hydrocarbon dewpoint control.
- That the operating pressure for both hydrocarbon dewpoint control and carbon dioxide removal be about 540 psia.

This above recommendations were accepted by the Technical Advisory Committee.

5. PROCESS DESCRIPTION

The Facilities process systems shown in block diagram form in Figure 1, and in more detail in Process Flow Diagram, Figure 2, include inlet separation and field fuel gas facilities, NGL extraction, CO_2 removal, sales gas compression and chilling, CO_2 solvent regeneration, and NGL fractionation. The process flow is similar for the four cases which were developed.

5.1 INLET SEPARATION AND FIELD FUEL GAS FACILITIES

Feed gases originating from the Gathering Centers and Flow Stations enter the Sales Gas Conditioning Facilities through the existing Central Compressor Plant inlet separators. These separators serve as liquid slug catchers and, in conjunction with downstream filter separators, serve to remove and recover any entrained liquids or particulates from the feed gases. Feed gas for the existing Field Fuel Gas Unit is withdrawn downstream of the filter separators. The Field Fuel Gas Unit feed is compressed in one of the existing first-stage injection compressors to between 1700 and 1800 psig. In the Field Fuel Gas Unit, the gas is cooled to -40°F at 850 psig by heat exchange and Joule-Thompson expansion. Cold vapor and condensed liquid are separated and the net Field Fuel Gas Unit conditioned gas is warmed by heat exchange with feed gas and goes to the Trans Alaskan Pipeline System fuel line. Cold separator liquid is also warmed by heat exchange with feed gas and is partially vaporized at about 635 psig. The separator vapor returns to the main Sales Gas Conditioning Facilities feed, and the net separator liquid joins the deethanizer feed stream.

5.2 NGL EXTRACTION

The feed stream from the inlet separators flows to the four parallel gas conditioning trains of the NGL Extraction and CO_2 Removal processes. Each train can condition 33% of the total flow, thus effectively providing one spare train. Within each of these trains the feed gas is combined with the SELEXOL stripper overhead gas and cooled to -30°F by heat exchange and propane refrigeration. Condensed liquids are separated from the cooled feed stream in the low-temperature separator and pumped through a feed gas heat exchanger where they are heated to 15°F. A partial demethanization flash occurs in the deethanizer feed flash drum, and the remaining liquid is heated to about 88°F by further exchange with feed gas and fed to the deethanizer. This 15°F flash separation serves to simplify both the design and operation of the deethanizer.

5.3 CO_2 REMOVAL

The vapor from the low-temperature separator is heated to about 20°F by exchange with feed gas and fed to the SELEXOL absorber along with deethanizer feed flash drum vapor, deethanizer overhead product gas, and SELEXOL recycle flash gas. In the absorber the feed gas is contacted countercurrently with lean SELEXOL solvent which absorbs the CO_2, a substantial portion of methane and ethane, most of the propane and essentially all of the heavier hydrocarbons from the gas. Cooling is required

in the circulating solvent system to maintain the design operating temperatures. A propane refrigerated intercooler is provided on the absorber to effect this cooling. Absorber overhead gas is warmed by heat exchange with feed gas and then routed to the pipeline gas compressors.

5.4 PIPELINE GAS COMPRESSION AND CHILLING

The conditioned gas streams from the four NGL extraction/CO_2 removal trains are combined. The net propane product and most of the butanes product from fractionation can be vaporized into the combined gas stream at this point. After compression and aftercooling in the existing Central Compressor Plant equipment, the conditioned gas stream is chilled to 25°F for delivery to the gas pipeline.

5.5 CO_2 SOLVENT REGENERATION

The SELEXOL solvent system is a simple recirculating loop. Solvent rich in CO_2 first flows from the absorber through a hydraulic power recovery turbine to a recycle flash drum. In the recycle flash drum a large percentage of the methane coabsorbed with the CO_2 is vaporized and compressed back to the absorber feed. Rich SELEXOL from the recycle flash drum flows through another hydraulic turbine to an intermediate pressure (IP) flash drum. A large part of the coabsorbed ethane, as well as CO_2 vapors, are released in the intermediate pressure flash. Solvent from the intermediate pressure flash drum is routed to the atmospheric, or low-pressure flash drum where the bulk of the absorbed CO_2 and coabsorbed propane and heavier hydrocarbons are released. The low-pressure flash gases are compressed to a nominal 325 psig level and routed to the local fuel fractionator. A stripper is required to reduce the CO_2 content of the lean solvent to the level required to condition gas to the 1 percent CO_2 level. Solvent from the low-pressure flash drum is pumped to the SELEXOL stripper where it contacts a slipstream of treated gas from the absorber. The stripping gas from the absorber is depressured through two expander stages for power generation and refrigeration recovery. Stripper overhead vapor is compressed back to feed gas pressure and recycled to the feed gas NGL extraction system for recovery of stripped hydrocarbons. Stripped lean solvent is pumped from the stripper back to the absorber, thus completing the circuit.

5.6 NGL FRACTIONATION

The single-train fractionation facilities consist of the local fuel fractionator, deethanizer, depropanizer, and debutanizer. All of these columns are reboiled by direct fired heaters. Compressed SELEXOL low-pressure flash gas is fed to the local fuel fractionator to recover the bulk of the propane and heavier hydrocarbons from the gas. The column has a refrigerated overhead condenser and is similar to a deethanizer. Separate feed-overhead heat exchangers are used for the local turbine and heater fuel portions of the overhead product. Propane is added to the turbine fuel portion of the overhead product for enrichment. This propane is vaporized in the feed-overhead exchanger. Local fuel fractionator bottoms product is fed to the depropanizer.

The deethanizer feed is made up of deethanizer feed flash liquids and NGL from the Field Fuel Gas Unit. The deethanizer operates at a nominal 450 psig with a propane-refrigerated condenser. Deethanizer overhead vapor product is compressed and can go either to field fuel or to SELEXOL absorber feed. Deethanizer bottoms product is fed to the depropanizer along with local fuel fractionator bottoms. The depropanizer produces a liquid propane overhead product stream. The low propane content depropanizer bottoms product can be blended directly into crude oil or fed to the debutanizer. The debutanizer produces a liquid butanes overhead product and a pentanes-plus bottoms product. The debutanizer overhead product can be almost totally injected into the pipeline gas without exceeding the pipeline gas hydrocarbon dewpoint specification or can be blended into the crude oil up to true vapor pressure limitations. The process design included the cooling facilities required for NGL and crude blending. These facilities are excluded from the summary cost estimate but are included in the cost estimate details in Section 11 of this volume.

A system is provided to inject the liquid feed for any column in the fractionation facilities alternatively into the producing formation. Therefore, an upset or equipment failure in the unspared fractionation facilities will not impair either crude oil production or pipeline gas deliveries.

A small sidestream rectifier is utilized on the depropanizer to provide refrigerant grade propane as makeup for the refrigeration system. This column draws a small ethane-free vapor feed from below the depropanizer feed tray and produces a very pure propane overhead product. The bottoms are pumped back to the depropanizer.

5.7 FUEL SYSTEMS

The intermediate-pressure flash gas is collected from the CO_2 removal trains and compressed to a nominal 500 psig for use in the field fuel. Compressor discharge heat is used to vaporize propane. The propane is injected into this stream for heating value control. Field fuel requirements greater than those available from this flash gas stream are met by adding Field Fuel Gas Unit conditioned gas (in excess of Trans Alaskan Pipeline System requirements), deethanizer overhead vapor, and low temperature separator vapor in that order. The combined field fuel gas has a relatively high hydrocarbon dewpoint. This gas is heated to 140°F by exchange with the exhaust gas from the field fuel gas compressor turbine driver to prevent condensation in the insulated field fuel distribution system.

In situations where the field fuel requirement is relatively low, there may be an excess of SELEXOL intermediate-pressure flash gas. At these times, excess field fuel compressor discharge will be bled into the local turbine fuel system. This, in turn, will create an excess of local fuel fractionator overhead vapor. During this operation, the excess CO_2-rich local fuel fractionator overhead can be compressed and reinjected into the producing formation. If the local fuel fractionator is shut down, the feed to this column can be used for local fuel, and the excess feed can be injected using both CO_2 compressors. Also, during periods of high local fuel demand, field fuel compressor discharge can be used to supplement local fuel fractionator overhead.

6. PLANT YIELDS

In addition to the nominal 2,000 MMSCFD of pipeline gas conditioned by the Facilities there are a number of other streams that are separated incidental to the pipeline gas conditioning. These include the high CO_2 content flash gases from the regeneration of the SELEXOL® solvent and the NGL. The flash gases are utilized as fuel in the Facilities and to supply the fuel requirements of the Prudhoe Bay Unit. The NGL, which includes separate propane, butane, and pentanes-plus streams, may be blended into either the fuel streams (propane) to control heating value, the pipeline gas to the hydrocarbon dewpoint limitation (propane or butane) or into the crude (butane or pentanes-plus) as limited by the vapor pressure specification.

Figure 8 is a block flow diagram of plant stream sources and disposition and shows one possible blending scheme for the various products. The design anticipates that there will be a significant variation in the fuel requirements of the Facilities between the extremes of summer and winter operation. The demand for fuel by the Prudhoe Bay Unit will vary both as a function of season and time as well as oil production rates. The blending of butanes into either pipeline gas or crude is controlled by the pipeline hydrocarbon dewpoint limitation or by economics. These variations have been allowed for in the design of the Facilities. Thus an almost infinite number of blending schemes is possible permitting effective and economic utilization of all streams from the Facilities. The scheme illustrated in Figure 8 represents the maximum anticipated demand for fuel by the Prudhoe Bay Unit (Field Fuel) and assumes no blending of butanes to the pipeline gas; in actuality about 97.8% of the butanes can be blended into the pipeline gas without exceeding the assumed hydrocarbon dewpoint specification. (See Volume II for butanes blended into 1260 pipeline case.)

The gas requirements of the Trans Alaskan Pipeline System will normally be provided by gas conditioning in the existing Field Fuel Gas Unit. The flash liquid and vapor streams resulting from this operation will be processed in the Sales Gas Conditioning Facilities.

Tables 6-1, 6-2, 6-3, and 6-4 show the quantities, properties and compositions for the various feed and product streams for the same case as Figure 8. In addition, Tables 6-1 and 6-3 show the same information for the maximum butanes blended into pipeline gas. Depending upon the particular case there will be some variation in the quantities, properties and compositions of all streams. For design purposes material balances have been developed only for the minimum and maximum Prudhoe Bay Unit fuel gas demands.

Table 6-1. Feed From Gathering Centers and Flow Stations

6-1A. SOURCES AND COMPOSITIONS	From Gathering Centers	From Flow Stations	Total
Feed Gas (MMSCFD)(1)	1400.0	1400.0	2800.0
Compositions - Volume % as Gas			
H_2S (ppmv)	8 ppmv	8 ppmv	8 ppmv
CO_2	12.72	12.54	12.63
N_2	0.45	0.49	0.47
Methane	74.35	74.00	74.17
Ethane	6.33	6.61	6.47
Propane	3.43	3.52	3.48
Butanes	1.60	1.72	1.66
Pentanes-plus	1.12	1.12	1.12
	100.00	100.00	100.00

6-1B. OVERALL MATERIAL BALANCE	
Stream	Volume (MMSCFD)(1)
Feed from Gathering Centers	1400.0
Feed from Flow Stations	1400.0
Total Feed	2800.0
Sales Gas-Net	2000.6
Propane-Balance over fuels	37.2
Butanes	41.3
Pentanes-plus	31.9
Fuels	689.0
Total Product	2800.0

(1) Standard Conditions - 14.65 psia and 60°F.

RMP

Table 6-2. Fipeline Gas

	As Conditioned	Propane Blended (6)	Propane Plus Butane Blended (7)
Volume Produced - MMSCFD (1)	2000.6	2037.8	2078.2
MMSCFD (2)	1989.7	2026.7	2067.0
CO_2 content - vol.% (3)	0.50	0.49	0.49
Hydrocarbon Dewpoint @ 1100 psia-°F	-60 approximate	-50 approximate	-10.
Heating value			
Higher heating value - Btu/SCF (4)	1034	1061	1106
- Btu/SCF (5)	1022	1048	1092
Lower heating value - Btu/SCF (8)	930	955	994
H_2S content Grains/100 SCF	<1.0	<1.0	<1.0
Water Dewpoint @ 1100 psia -°F	-35°	-35°	-35°
Composition Volume % as Gas			
H_2S	1 ppmv	2 ppmv	2 ppmv
CO_2 (3)	0.50	0.49	0.49
N_2	0.62	0.61	0.60
Methane	94.29	92.57	90.77
Ethane	4.47	4.50	4.41
Propane	0.08	1.75	1.72
Butanes	0.03	0.07	1.95
Pentanes	0.01	0.01	0.06
	100.00	100.00	100.00

(1) Standard conditions - 14.65 psia and 60°F (State of Alaska Base).
(2) Standard condition - 14.73 psia and 60°F (FERC Base).
(3) SGCF was designed at 0.5 vol. % CO_2 to guarantee 1.0 vol. % max. in Pipeline Gas.
(4) Gross, dry, actual at 14.65 psia and 60°F.
(5) Gross, wet, actual at 14.73 psia and 60°F.
(6) This is the as-conditioned gas when blended with propane in excess of fuel requirements.
(7) This is the as-conditioned gas when blended with propane in excess of fuel requirements plus butanes to the hydrocarbon dewpoint limitation.
(8) Net, dry, ideal at 14.65 psia and 60°F.

RMP

Table 6-3. Fractionator Products

	Propane	Butanes		Pentanes-plus
Net Extracted				
BPD	52,350	31,290		28,700
MMSCFD (1)	80.3	41.3		--
Disposition		Min.	Max.	
To Pipeline Gas				
BPD	24,270	-0-	30,602	-0-
MMSCFD (1)	37.2	-0-	40.4	-0-
To Fuel Gas Systems				
BPD	28,080	-0-	-0-	-0-
MMSCFD (1)	43.1	-0-	-0-	-0-
To Crude				
BPD	-0-	688	31,290	28,700
Composition - Volume % as gas				
H_2S	38 ppmv		-	-
CO_2	0.01		-	-
Ethane	6.40		-	-
Propane	91.59		0.17	-
Butanes	2.00		97.31	6.01
Pentanes-plus	-		2.52	93.99
	100.00		100.00	100.00

(1) Standard Conditions - 14.65 psia and 60°F.

RMP

Table 6-4. Fuel Streams

	For TAPS	For Prudhoe Bay Unit (Field Fuel)	For Local Turbine	For Local Heater
MMSCFD (1)	40.9	399.4	192.0	56.7
Lower Heating Value-Btu/SCF	851	825	475	212
MM Btu/hr.	1,450	13,729	3,800	500
Hydrocarbon Dew Point -°F (2)	-40°F @ 840 psig	27°F @ 500 psig	17°F @ 300 psig	60°F @ 60 psig
Composition - Volume % as gas				
H_2S	4 ppmv	22 ppmv	38 ppmv	40 ppmv
CO_2	11.44	36.40	75.08	87.21
N_2	0.58	0.13	-	-
Methane	81.54	37.73	2.71	1.46
Ethane	4.70	16.24	9.23	9.04
Propane	1.37	8.84	12.67	2.29
Butanes	0.31	0.60	0.30	-
Pentanes-plus	0.06	0.06	0.01	-
	100.00	100.00	100.00	100.00

(1) Standard conditions - 14.65 psia and 60°F.
(2) Pressures are system-operating pressure.

7. PROCESS AUXILIARY SYSTEMS

Utility systems for the Sales Gas Conditioning Facilities were developed to the detail necessary for estimating cost. They include:

- Electrical power generation system.
- Glycol cooling medium system.
- Glycol process heating medium.
- Glycol module heating medium system.
- Nitrogen inert gas system.
- Service and instrument air systems.
- Closed hydrocarbon drainage system.
- Potable and utility water system.
- Sanitary sewer system.
- Hydraulic power center systems.
- Communication systems.
- Safety and fire protection systems.

The peak electrical power requirement for the Facilities is about 65 megawatts. Power recovery generators on the stripping gas expanders and solvent streams provide 12 megawatts of this power. The balance is generated by a three-generator unit utility power plant. An on-line spare generator unit is provided during all load conditions. Lower loads during cold ambient temperature conditions permit shutting down a unit for planned maintenance without affecting the minimum design spare generating capacity. Emergency power for critical control, lighting, fire protection and heating systems is provided by smaller turbine generator units.

8. FACILITY LOCATION AND ARRANGEMENT

Because this Study assumed use of the existing first-stage injection compressors as a base case, the Sales Gas Conditioning Facilities were located close to the Central Compressor Plant. This location takes advantage of the existing field gas gathering lines to the Central Compression Plant and the existing gas injection wells near the Central Compression Plant. Its proximity to the existing docks reduces time required for low-speed transporter movement of the large number of modules from the docks to the site. A site location plan is shown as Figure 3.

Modular construction is a proven, cost effective method for constructing facilities at Prudhoe Bay. Modular design utilizes a structural steel base supporting a steel frame building housing the equipment. The module size and base structure are designed to allow movement by low-speed transporters. Modules are assembled to the maximum extent possible at the "Lower 48" fabrication site to avoid the significantly higher North Slope costs. The modules are then barged to the North Slope and set on prepared gravel and piling sites. The modules are interconnected after placement, and utilidors (enclosed pipeways/walkways) are used where required to provide the necessary safe module separation.

The layout of the modules included in the facilities is centered around the four gas conditioning trains with space reserved for up to a 50% capacity expansion. Process and support facilities are centrally located near the gas conditioning trains. This was done, without compromising general safety separation criteria, to service the gas conditioning trains as efficiently as possible. The emergency flares are located a safe distance from the process facilities. The crude cooling and NGL crude blending facilities are located near the Trans Alaskan Pipeline System Pump Station No. 1. The Construction Camp and Operations Center are located a convenient but safe distance from the process facilities and the pipeline routes. Overall module layouts of the process facilities and the camps are shown on Figure 4.

Figure 7 illustrates a typical layout drawing for a 33% capacity gas conditioning train, which includes nine modules and one utilidor.

9. MODULE FIRE AND SAFETY CONSIDERATIONS

Totally enclosed modularized facilities are ideal for providing controlled environmental conditions during construction and operation on the North Slope. However, modular construction requires special ventilation and fire protection measures. The modules are maintained within a controlled temperature range using heated makeup air. Exhaust fans insure proper ventilation and prevent an accumulation of hydrocarbons. Other protective measures and safety systems considered in this study include:

- Emergency Shutdown System for process isolation of all or portions of the Facilities.
- Process area isolation to prevent the spread of hydrocarbon vapors or fire.
- Gas Detection and Fire Sensing Systems.
- Halon inerting and fire extinguishing systems.
- Firewater backup extinguishing systems.
- Liquid hydrocarbon and firewater drainage systems.
- Relief, vent and flare systems.
- Mobile fire fighting equipment

10. IMPLEMENTATION PLAN

The implementation plan provides a sequenced checklist of scheduled events for the entire project from initiation of detailed design engineering through startup of the Facilities. The plan provides the basis for estimating the cost of engineering, procurement, fabrication, logistics and erection activities. The plan assumes early and effective use of proven scheduling, quality assurance, cost control, and material control procedures to assure completion of the Project on time and within the authorized funding.

10.1 SCHEDULE

The implementation plan schedule milestones illustrated in Figure 5 show an exceptionally tight sequence of activities from initiation of final process design to startup. With careful planning, timely funding, and absence of regulatory or legal delays it would be possible to complete the Facilities with a 4-1/2 year lead time.

In order to have a 66% capacity startup in January, 1983, it is necessary to initiate final process design in September, 1978. Full capacity startup is not possible before July, 1983. In order to achieve either schedule, it is necessary to conclude detail design engineering contractor selection no later than January, 1979. Final process design must be completed by December, 1978, and detailed mechanical design must commence no later than January 1, 1979. Time sensitive activities during the first three months of detailed design include:

- Preparation of specifications and requisitions for critical delivery equipment and materials such as turbines, compressors, heavy-wall vessels, and low-temperature piping.
- Design of the first phase of the Construction Camp and its associated facilities to support a spring 1980 installation at Prudhoe Bay.
- Initiation of permitting activities including the gathering of baseline air quality data required for construction permits in support of 1980 and 1981 Prudhoe Bay erection activities.

10.2 FUNDING

Required funding approvals are shown on the schedule, phased as required to support critical design and procurement activities. To meet the schedule, funding for these activities should be provided by late 1978 and preferably prior to engineering contract negotiations. Total project funding is required by December, 1979, which coincides with award date for fabrication contracts. Prior to December, 1979, total project funding approval, commitments totaling approximately $500,000,000 will be required for engineering and ordering critical equipment.

10.3 PROCUREMENT

Given present market conditions and recognizing possible impact of concurrent projects such as the Alaska Highway Gas Pipeline System and the Prudhoe Bay Unit production facility work, procurement of long lead items included in the 1981 sealift should begin in March, 1979.

10.4 CONSTRUCTION

The general construction plan assumes three phases of work involving a small sealift in 1980 supplemented by truck hauling followed by two major sealifts in 1981 and 1982. Pre-sealift work must be initiated in 1980 both at "Lower 48" fabrication sites and at Prudhoe Bay.

The implementation plan assumes an optimized North Slope labor force of 1,000. This manpower level dictates the Construction Camp size and associated support costs for Prudhoe Bay. It also indirectly dictates the fabrication manpower level. Scheduled and peak manpower requirements are shown in Table 10-1.

Table 10-1. Manpower Requirements

	"Lower 48" Fabrication		North Slope Erection	
BASE CASE	Total Manhours	Peak Manpower (Year)	Total Manhours	Peak Manpower (Year)
Full Startup	9,366,000	3,000 (81,82)	5,435,000	800 (82)
Phased Startup	9,387,000	4,500 (81)	5,389,000	1,000 (81,82)
ALTERNATE CASE				
Full Startup	10,141,000	3,500 (82)	5,720,000	800 (82)
Phased Startup	10,134,000	4,750 (81)	5,656,000	1,000 (81,82)

The fabrication sites are assumed to be located adjacent to major deep-draft waterways which will accommodate ocean-going barges. West Coast fabrication sites were assumed for planning purposes. The West Coast provides favorable weather conditions, adequate manpower and the shortest shipping distance. Fabrication site size requirements are estimated at 200 acres for 1981 and 80 acres for 1982. The job size and construction manpower requirements indicate that at least two sites must be considered as a planning basis. The estimate basis assumes that sites are completely unimproved and require grading, compacting and construction of module pads, offices, shops, warehouses, utility distribution systems, fencing, and barge loading facilities.

Support facilities at Prudhoe Bay include a temporary Construction Camp and a permanent Operations Center along with required power generation, water supply, and sewage and water treating facilities. The Construction Camp would be erected in two phases. The first phase, erected during early 1980, would provide lodging and support for the approximately 450 staff and craft personnel involved in gravel, piling, and other early construction work from June, 1980, to June, 1981.

Since the peak period of North Slope construction is scheduled for the fall of 1981, the second phase of camp construction would be completed during the spring of 1981. This expansion increases the size of the construction camp to accommodate the projected peak construction manpower of 1,000.

The completed Construction Camp will include lodging, kitchen, dining room, recreational facility, laundry, medical room, and office space. Utility buildings will include garages, warehouses, miscellaneous flammable liquid storage, bulk gasoline and diesel fuel storage and dispensing terminal, welding shop and fabrication shop. Facilities are provided for emergency power generation, mobile fire protection, waste incineration, water treatment, and sewage treatment. Some of these will be permanent facilities associated with the Operations Center.

The Operations Center erected in 1981 will be a 200-man modular facility designed to house and support permanent operations, maintenance, and staff personnel. During construction, the Operations Center would be used to house Plant Owner/Operator representatives, operators, and startup and maintenance personnel assigned to monitor and inspect construction activities. Included in initially installed facilities are utilities which will be used to support both the Construction Camp and the Operations Center. These will be trucked overland in 1980. Operations Center units delivered in the 1981 sealift will include administrative offices, kitchen, medical room, laundry, recreational facility, and support systems similar to those erected earlier for the Construction Camp.

10.5 LOGISTICS

Docking facilities at fabrication sites should be capable of dead loading modules; i.e., loading a barge that is flooded and bottomed. A general cargo storage and staging area should be provided with appropriate lighting and support equipment. Both 1981 and 1982 module loadout programs will require approximately 30 days each to complete preceded by approximately two weeks of module preparation.

Barge requirements to move the completed modules and general cargo are estimated as follows:

	PHASED STARTUP			FULL STARTUP		
	1980	1981	1982	1980	1981	1982
BARGES REQUIRED	2	25	11	2	24	16

The two startup cases require approximately the same square footage of barge space. In the phased startup, larger barges but fewer are required.

Two possibilities were considered for module offloading at Prudhoe Bay as follows:

(1) A new separate causeway and dock for the Facilities could be constructed independent of existing North Slope facilities. Offloading of modules would then be independent of the other projected Prudhoe Bay Unit projects.

(2) The existing dock facilities owned by SOHIO/ARCo./ EXXON could be expanded and the offloadng coordinated with concurrent North Slope projects.

The latter approach is assumed for our planning basis. This approach results in less capital expenditure and tends to minimize environmental impact. The use of these facilities would require close coordination between the Sales Gas Conditioning Facilities project and other concurrent North Slope projects to ensure timely offloading of all modules and general cargo. Module offloading, estimated to take 21 to 34 days, can be accomplished through the use of both crawler transporters and newly developed rubber-tired vehicles.

10.6 STARTUP

Facilities startup activities will begin approximately six months prior to mechanical completion. It is assumed that an Operator/Owner startup team will be formed and used in a technical and supervisory capacity with regular operating personnel performing the physical startup of the facility.

11. ESTIMATED COSTS

The Sales Gas Conditioning Facilities cost estimates were prepared on a mid-1978 cost basis. Escalation was estimated on an item by item basis and is extremely sensitive to implementation schedule.

11.1 ESTIMATING METHOD

The estimating method utilized the modular construction cost experience of Atlantic Richfield Company (Unit Operator - East) and The Ralph M. Parsons Company, from production facilities development on the east side of the Prudhoe Bay Field.

The estimate was developed from:

- Individual Module Layouts to Determine Size and Weight.
- Major Equipment Estimating Quotations.
- Major Piping Layout.
- Single-Line Electrical Drawings.
- Detailed Analysis of "Lower 48" and North Slope Labor Requirements.
- Logistics Analysis.

The estimate basis is presented in detail in Volume III of this Report.

11.2 ESTIMATED COSTS

Estimated costs, including contingency and excluding the Crude Oil Cooling Facilities, for each of the four cases studied are tabulated below:

	Mid-1978 Basis (Dollars)	Escalated Basis (Dollars)
Base Case Full Startup	1,571,500,000	1,962,300,000
Base Case Phased Startup	1,581,200,000	1,964,500,000
Alternate Case Full Startup	1,688,400,000	2,109,700,000
Alternate Case Phased Startup	1,701,700,000	2,107,200,000

A Unit detail of these costs is shown in Table 11-1.

The escalation applied to each of the four cases is based upon a Ralph M. Parsons Company composite analysis of various inflation forecast

sources listed in the estimate basis. (Detailed in Volume III Section 12.) The escalation percentages were then applied to the costs in accordance with the implementation schedule. Based on the current plan and schedule, a weighted average annual escalation of 6.73% was applicable.

11.3 CONTINGENCY ANALYSIS

Contingency funds were included in the costs presented in this report; the contingency percentage used was determined by risk analysis using RISKAN.® Each major cost account was evaluated for probable accuracy variation taking into account the engineering design basis, extent and accuracy of material takeoffs and estimating and pricing methods. Where escalation was included in the costs, the escalation was considered in the risk analysis. The details of the risk analysis are shown in Volume III of this report.

The contingency selected gives a 90 percent probability that the estimated cost including contingency will not be exceeded, provided the design and schedule are followed as planned in this study.

11.4 OTHER FACILITY COSTS

Crude oil cooling facilities costs are excluded from the total cost of the Facilities. These costs are shown separately in Table 11-2.

11.5 DELAY COST TREND

Delays in proceeding with this project will increase the cost of the facilities in accordance with escalation forecasts. Delay cost trends calculated for delay of completion year to 1984, 1985, and 1986 are as follows when utilizing the same 4-1/2 year implementation plan:

	Incremental Delay Cost	
Full Capacity Delivery Year	Base Case (Dollars)	Alternate Case (Dollars)
1984	$160,000,000	$170,000,000
1985	$350,000,000	$370,000,000
1986	$540,000,000	$580,000,000

Delay costs are calculated by an application of escalation to equipment and materials, labor and support, engineering design and management and plant operator's costs, then with recalculation of contingency using RISKAN procedure. This procedure indicates a delay cost of approximately 9 percent per year. These costs are not included in the project estimated costs presented in subsection 11.2.

11.6 COSTS INCLUDED IN THE ESTIMATES

The following costs have been included in the estimates. The estimate detail (Volumes VI and VII) provides information on these costs:

- Engineering, Procurement

- Equipment and Materials
- Module Fabrication
- North Slope Erection
- Construction Management and Supervision
- Fabrication Site Lease, Site Development and Temporary Facilities
- North Slope Camp and Other Temporary Facilities
- Barging Costs
- Operations Center
- SELEXOL® License Fee
- Initial Charge of Chemicals and Operating Supplies.
- Spare Parts
- Dual fuel system and combustor retrofit in Central Compression Plant
- Costs Paid Directly by the Plant Operator/Owner (Plant Operator Cost):
  - Preliminary Engineering Design Study *
  - Plant Operator Engineering and Construction Supervision
  - Plant Operator Commissioning and Startup Costs *
  - Alaska ad Valorem and Borough Taxes *
  - Dock Use Charges

11.7 COSTS EXCLUDED

Costs excluded from the estimate are:

- Financing Costs
- Reimbursement for cost of Prudhoe Bay Unit Central Compression Plant

*Normally expensed by Operator/Owner

- Operating Costs
- Operating Supplies (SELEXOL, Glycol, Lube Oils), except Initial Charge Included in Estimate
- Sales Tax on In-Transit Materials
- Cost for Lost or Damaged Materials (or Insurance for)
- All-Risk Insurance
- Land/Mineral Leases at Prudhoe Bay
- Permit and Environmental Impact Statement Costs
- Unexpected Deviation from, Adverse Interperatation of, or Revision to Current Environmental Regulations
- Landing Strip or Airport Facilities at Prudhoe
- Dock Expansion Costs (Dock Use Charge Included)
- Use of Prudhoe Bay Unit Roads and the haul road from Fairbanks to Prudhoe Bay
- Facility Removal Costs at End of Production Life
- Revision to Schedule or Major Delays
- Salvage, Scrap or Transfer Value of Surplus or Cancelled Equipment/Material
- Process Optimization Engineering Cost
- Contingency for Significant scope changes

11.8 CASH FLOW

Projected cash flow including contingency and escalation, but exclusive of Crude Oil Cooling Facilities (Unit 62), for the four cases included in this study are tabulated in Table 11-3. The base case, full startup commitment and expenditure curves are shown on Figure 9. The commitment curve reflects material commitments when ordered whereas construction costs are committed as spent.

TABLE 11-1. ESTIMATE SUMMARY
TOTAL DOLLARS IN MILLIONS

UNIT No.	DESCRIPTION	MID-1978 DOLLARS				ESCALATED DOLLARS			
		BASE CASE		ALTERNATE CASE		BASE CASE		ALTERNATE CASE	
		FULL STARTUP	PHASED STARTUP	FULL STARTUP	PHASED STARTUP	FULL STARTUP	PHASED STARTUP	FULL STARTUP	PHASED STARTUP
31-34	NGL Extr. & CO_2 - Train #1-4	177.6	177.6	177.6	177.6	177.6	177.6	177.6	177.6
41	Sales Gas Compression	6.7	6.7	-	-	6.7	6.7	-	-
42	Inlet Separation	-	-	7.8	7.8	-	-	7.8	7.8
43	Sales Gas Compression	-	-	59.2	59.2	-	-	59.2	59.2
45	Refrigeration	81.1	81.1	81.1	81.1	81.1	81.1	81.1	81.1
46	Field Fuel & CO_2 Fac.	28.3	28.3	28.3	28.3	28.3	28.3	28.3	28.3
51	NGL Fractionation	51.3	51.3	51.3	51.3	51.3	51.3	51.3	51.3
61	Utilities/Pipeways	140.5	140.5	141.8	141.8	140.5	140.5	141.8	141.8
63	Power Generation	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
80	Operations Center	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
	Total Equipment & Material	527.9	527.9	589.5	589.5	527.9	527.9	589.5	589.5
	Lower 48 Labor & Support	256.1	259.4	272.7	276.7	256.1	259.4	272.7	276.7
	North Slope Labor & Support	401.7	403.2	416.5	419.2	401.7	403.2	416.5	419.2
	Engineering, Design & Mgmt.	91.0	91.0	98.0	98.0	91.0	91.0	98.0	98.0
	Plant Operator's Costs:								
	Owner/Operator Engr. Teams	44.9	45.0	47.8	48.0	44.9	45.0	47.8	48.0
	Dock Use Charge	7.6	7.6	8.0	8.0	7.6	7.6	8.0	8.0
	Commissioning & Start-up	49.0	49.0	49.1	49.1	49.0	49.0	49.1	49.1
	Ad Valorem & Borough Taxes	63.5	67.5	67.4	72.7	63.5	67.5	67.4	72.7
	Mid-1978 Subtotal	1441.7	1450.6	1549.0	1561.2	1441.7	1450.6	1549.0	1561.2
	Escalation	-	-	-	-	294.9	287.9	318.0	303.6
	Contingency (@9% '78 Dollars @13% Esc. Dollars)	129.8	130.6	139.4	140.5	225.7	226.0	242.7	242.4
	Total Facility Estimate	1571.5	1581.2	1688.4	1701.7	1962.3	1964.5	2109.7	2107.2

NOTE: This estimate summary excludes Unit 62, Crude Oil Cooling Facilities.

ARCO

TABLE 11-2
CRUDE OIL COOLING FACILITIES - UNIT 62
ESTIMATE SUMMARY
TOTAL DOLLARS IN MILLIONS
(ALLOCATED FROM TOTAL ESTIMATE)

UNIT No.	DESCRIPTION	MID-1978 DOLLARS				ESCALATED DOLLARS			
		BASE CASE		ALTERNATE CASE		BASE CASE		ALTERNATE CASE	
		FULL STARTUP	PHASED STARTUP	FULL STARTUP	PHASED STARTUP	FULL STARTUP	PHASED STARTUP	FULL STARTUP	PHASED STARTUP
62	Crude Oil Cooling Facilities	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4
	Gravel	.3	.3	.3	.3	.3	.3	.3	.3
	Total Equipment & Material	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7
	Lower 48 Labor & Support	13.0	13.2	12.9	13.1	13.0	13.2	12.9	13.1
	North Slope Labor & Support	10.2	10.2	9.9	10.0	10.2	10.2	9.9	10.0
	Engineering, Design & Mgmt.	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
	Plant Operator's Costs								
	Owner/Operator Engr. Teams	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
	Dock Use Charge	.3	.3	.3	.3	.3	.3	.3	.3
	Commissioning & Start-up	1.9	1.9	1.7	1.7	1.9	1.9	1.7	1.7
	Ad Valorem & Borough Taxes	2.5	2.6	2.4	2.6	2.5	2.6	2.4	2.6
	Mid-1978 Subtotal	55.8	56.1	55.1	55.6	55.8	56.1	55.1	55.6
	Escalation	-	-	-	-	13.1	11.2	12.9	11.1
	Contingency (@9% '78 Dollars @13% Esc. Dollars)	5.0	5.0	5.0	5.0	9.0	8.7	8.8	8.7
	Total Unit 62 Estimate	60.8	61.1	60.1	60.6	77.9	76.0	76.8	75.4

RMP

Table 11-3. Cumulative Cash Flow
(Millions of Dollars)

Year	Quarter	Base Case		Alternate Case	
		Phased Startup	Full Startup	Phased Startup	Full Startup
1978	1-4	1.7	1.7	1.7	1.7
1979	1	8.0	8.0	8.0	8.0
	2	51.0	35.0	57.0	48.0
	3	100.0	60.0	117.0	87.0
	4	200.0	122.0	223.0	163.0
1980	1	288.0	189.0	319.0	231.0
	2	431.0	309.0	484.0	344.0
	3	584.0	457.0	658.0	487.0
	4	733.0	626.0	834.0	654.0
1981	1	887.0	798.0	1,015.0	852.0
	2	1,053.0	984.0	1,211.0	1,066.0
	3	1,172.0	1,127.0	1,321.0	1,211.0
	4	1,291.0	1,271.0	1,432.0	1,355.0
1982	1	1,396.0	1,434.0	1,606.0	1,537.0
	2	1,492.0	1,584.0	1,767.0	1,705.0
	3	1,626.0	1,635.0	1,824.0	1,762.0
	4	1,741.0	1,678.0	1,873.0	1,810.0
1983	1	1,821.0	1,795.0	1,958.0	1,935.0
	2	1,875.0	1,874.0	2,015.0	2,018.0
	3	1,938.0	1,936.0	2,080.0	2,082.0
	4	1,964.5	1,962.3	2.107.2	2,109.7

12. FUTURE DESIGN CONSIDERATIONS

A number of ideas were developed during the progress of the Study which, if determined to be viable and incorporated into the final design, could potentially result in significant capital savings and/or reduction in operating cost. It was not possible to evaluate all of these ideas during the Study because of schedule limitations.

Although some of these ideas apparently have obvious cost benefits and need only to be developed, others require economic evaluation and justification before they could be implemented. More detailed information on Facility ownership, value of conditioned gas, value of fuel gas, value of NGLs, transportation tariff, etc., must be known before these studies can be concluded. Some of these ideas may be evaluated concurrently with the development of the final design. These ideas are put forth in Volume IV.

Other of these ideas will impact the schedule and should be the first item of work if the Facilities are to be completed by July, 1983. The decision as to whether or not these ideas are to be incorporated in the final design should be made before starting the final design because:

- Incorporation will influence the scope of work for the final design.
- Time is required for the development work necessary for their application.

These ideas, which impact schedule, are outlined below and developed in detail in Volume II.

12.1 BASIC SELEXOL PROCESS DESIGN

The basic NGL/CO_2 extraction processes can potentially be modified by increasing the operating temperature of the low-temperature separator, altering the feed gas chilling and altering SELEXOL solvent chilling systems. The above changes would reduce both capital and operating costs.

12.2 REFRIGERATION SYSTEM OPTIMIZATION

Several possible configurations for the refrigeration facilities were examined in the Study. A centralized system with parallel compressors was selected. Further optimization of this system is possible. There are a number of areas where either the refrigeration level or load can be reduced. The impact of these improvements would be to reduce both the capital and operating costs of the refrigeration system. During the selection of the final configuration, it is suggested that a detailed analysis of the refrigeration process control system be conducted.

12.3 WASTE HEAT RECOVERY

Potential exists for further fuel conservation via additional waste heat recovery from the gas turbine exhaust gas. This potential is over

and above the heat recovery by using regenerative gas turbines in the design. The potential uses for this heat include:

- Reboiling of the fractionator towers
- Module heating

The impact of using waste heat would be to increase available gas for future disposition. The evaluation should consider the additional requirements for disposal of surplus low heating value gas during early and late years of the Facilities and Field operation.

12.4 REEVALUATION OF THERMODYNAMIC DATA

The proper selection and sizing of process equipment for the Facilities is largely dependent on thermodynamic data. For the purposes of this study the best available data were used. The quality of this data and hence the quality of the final design may be improved by:

- A comprehensive literature search and data evaluation covering the expected composition and operating conditions for this facility.
- Generation of new data for these facilities in the laboratory, where suitable data are not in the literature.

12.5 PIPELINE GAS SPECIFICATIONS

The gas pipeline specifications and delivery pressure adopted for this Study were established on the basis of the best available knowledge at the time the Study was started. A higher allowable CO_2 content of the delivered gas will have a significant impact on the facilities costs. It is recommended that the cost impact of the possible alternative specification for CO_2 content and gas pipeline pressure be evaluated for the overall conditioning and gas transmission system.

12.6 GAS TURBINE COMBUSTORS

It was determined that gas turbines with the proper combustor and control configuration can burn both low-Btu/high-CO_2 content fuel gas and normal-Btu fuel gas. Combustor testing and development will be required for the specific fuels available from these facilities. This work by the selected vendor or vendors should begin in the first quarter of 1979 to insure timely delivery of the gas turbines. In addition, data from these tests will be required to obtain permits.

12.7 SELEXOL ABSORBER/STRIPPER INTERNALS

There are several vendors of tower packings who claim very high hydraulic capacity for some of their packings. If these claims are valid it

would be possible to eliminate one SELEXOL train. However, these claims should be validated by independent testing prior to use of these packings.

12.8 ENVIRONMENTAL

Administration by local agencies of the Clean Air Act and Amendments of 1977 could impose requirements not perceived by this Study. Upon project initiation, the requirements should be determined as soon as possible and the impact on Facilities design and implementation should be established.

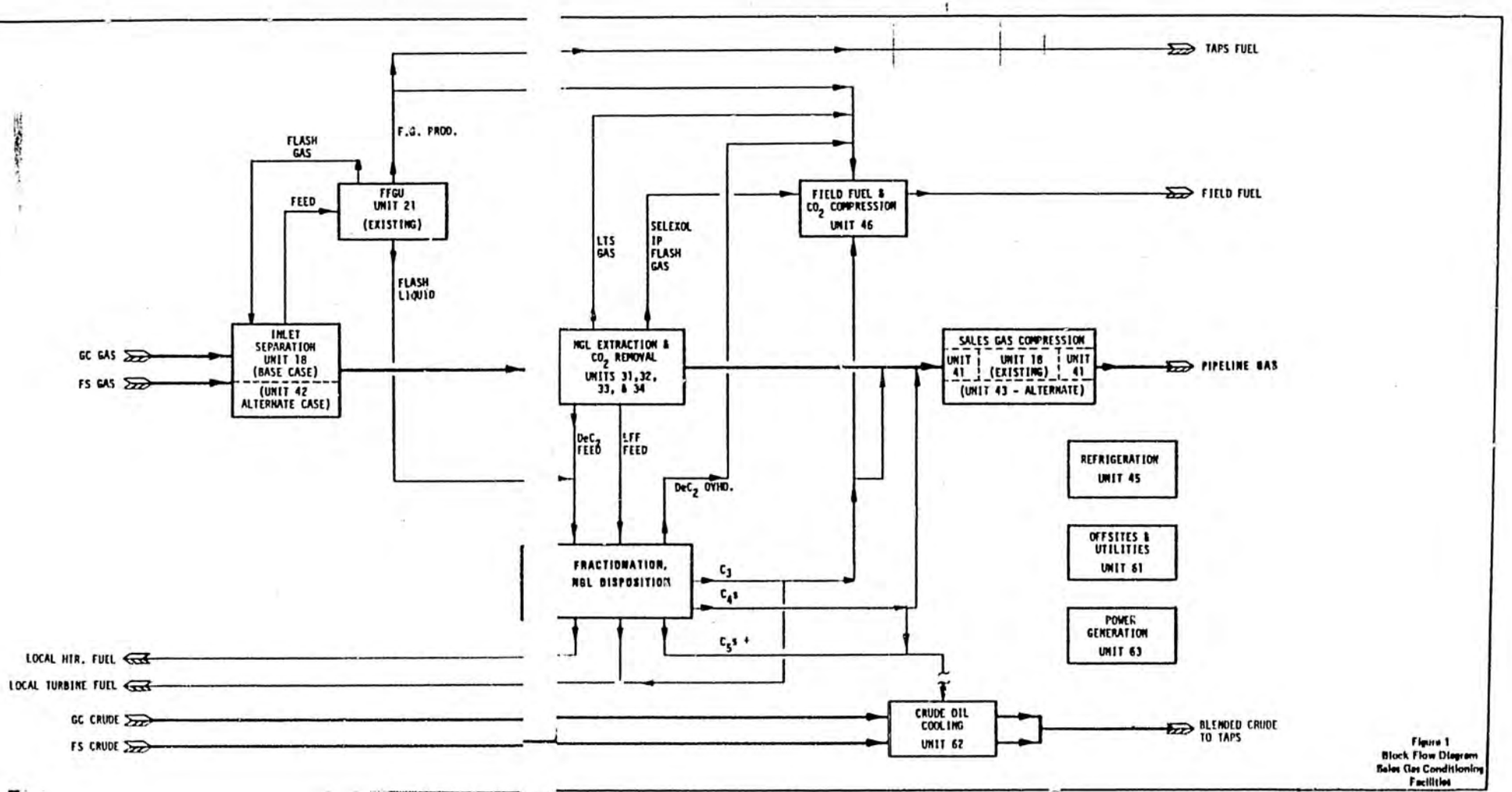
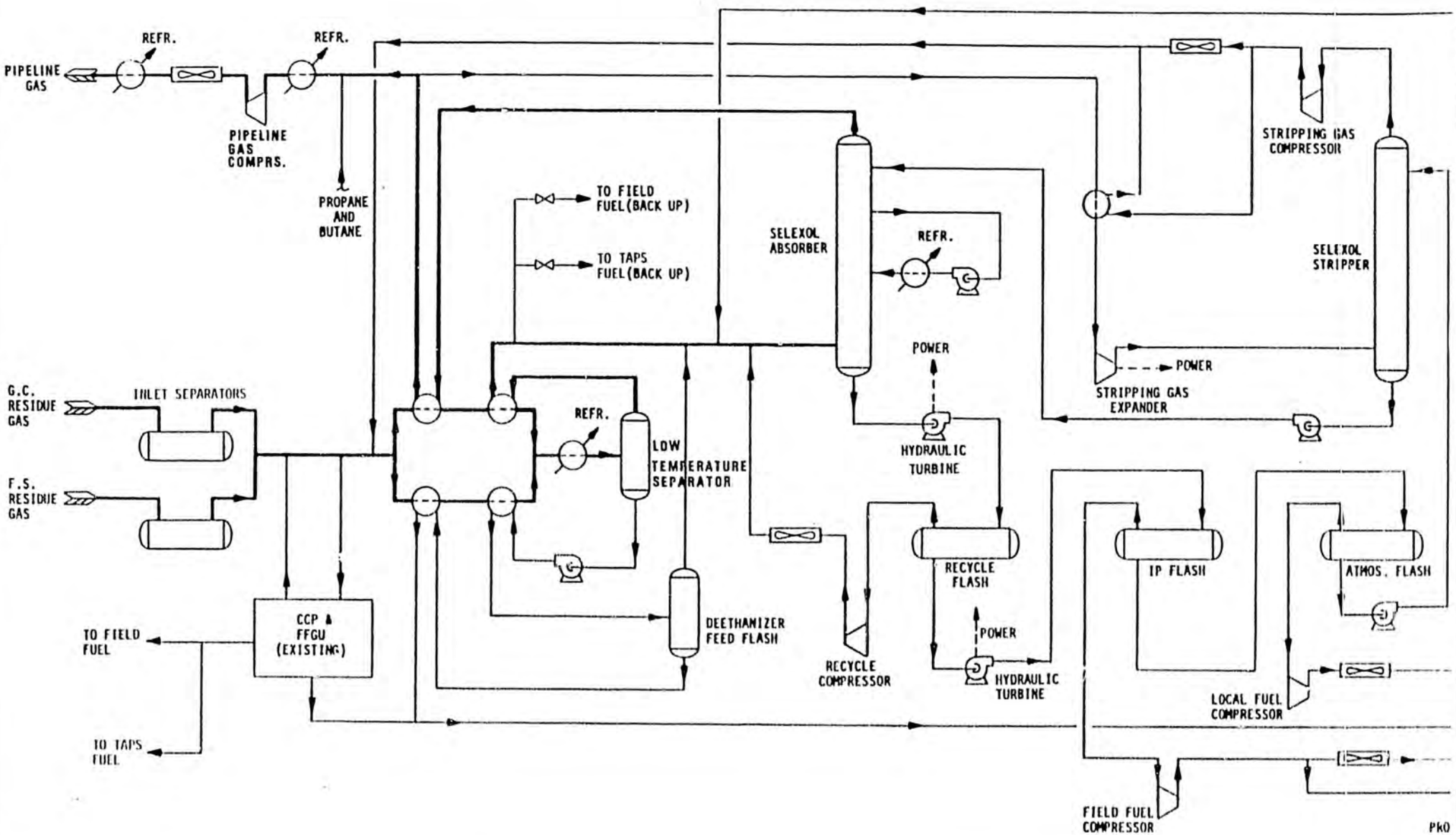


Figure 1
Block Flow Diagram
Sales Gas Conditioning
Facilities


REFR.
REFR.
PIPELINE GAS
PIPELINE GAS COMPRS.
PROPANE AND BUTANE
TO FIELD FUEL(BACK UP)
TO TAPS FUEL(BACK UP)
SELEXOL ABSORBER
REFR.
STRIPPING GAS COMPRESSOR
SELEXOL STRIPPER
POWER
POWER
STRIPPING GAS EXPANDER
HYDRAULIC TURBINE
G.C. RESIDUE GAS
INLET SEPARATORS
F.S. RESIDUE GAS
REFR.
LOW TEMPERATURE SEPARATOR
RECYCLE FLASH
IP FLASH
ATMOS. FLASH
CCP & FFGU (EXISTING)
TO FIELD FUEL
TO TAPS FUEL
DEETHANIZER FEED FLASH
RECYCLE COMPRESSOR
POWER
HYDRAULIC TURBINE
LOCAL FUEL COMPRESSOR
FIELD FUEL COMPRESSOR
PKO

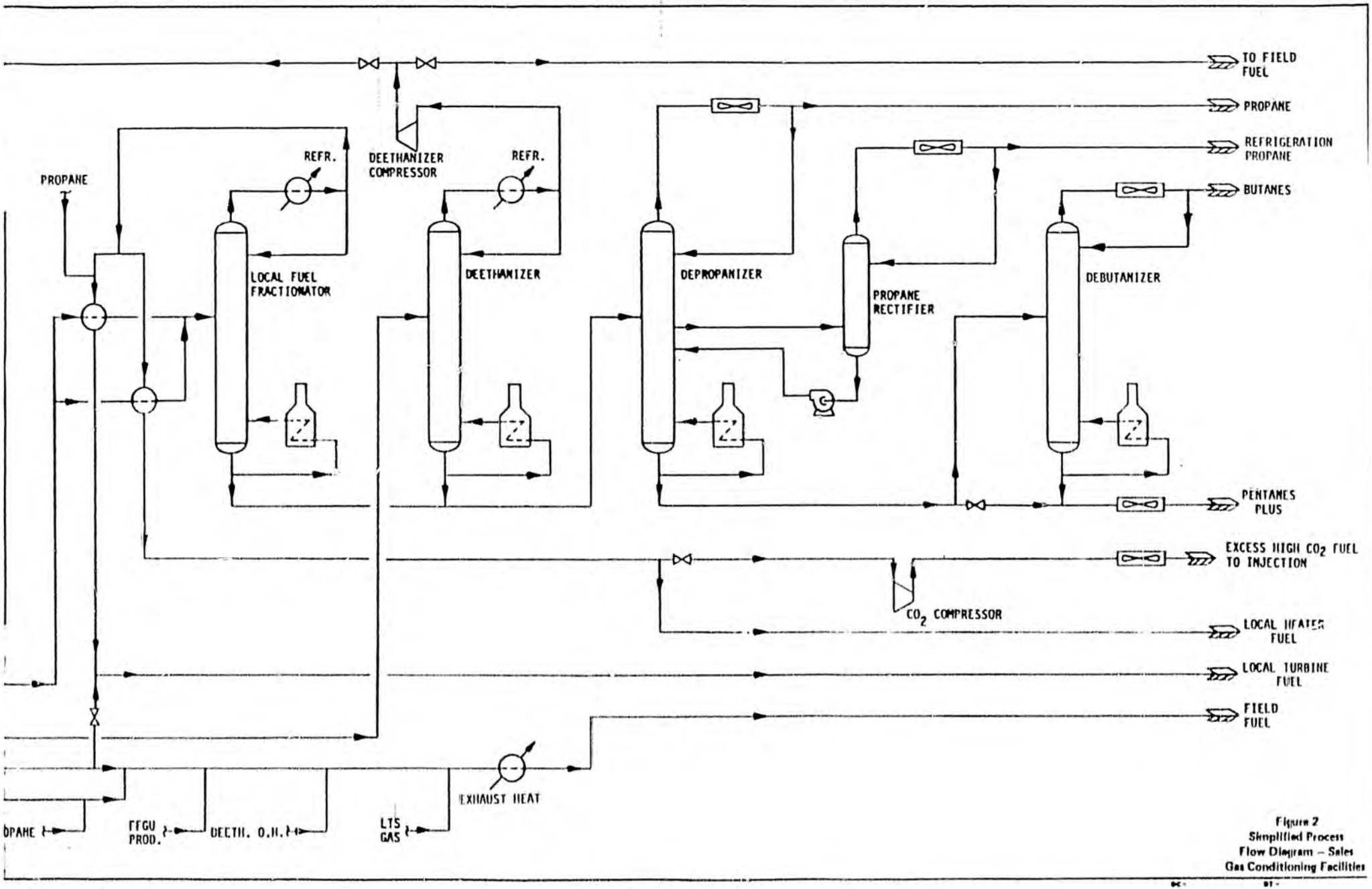
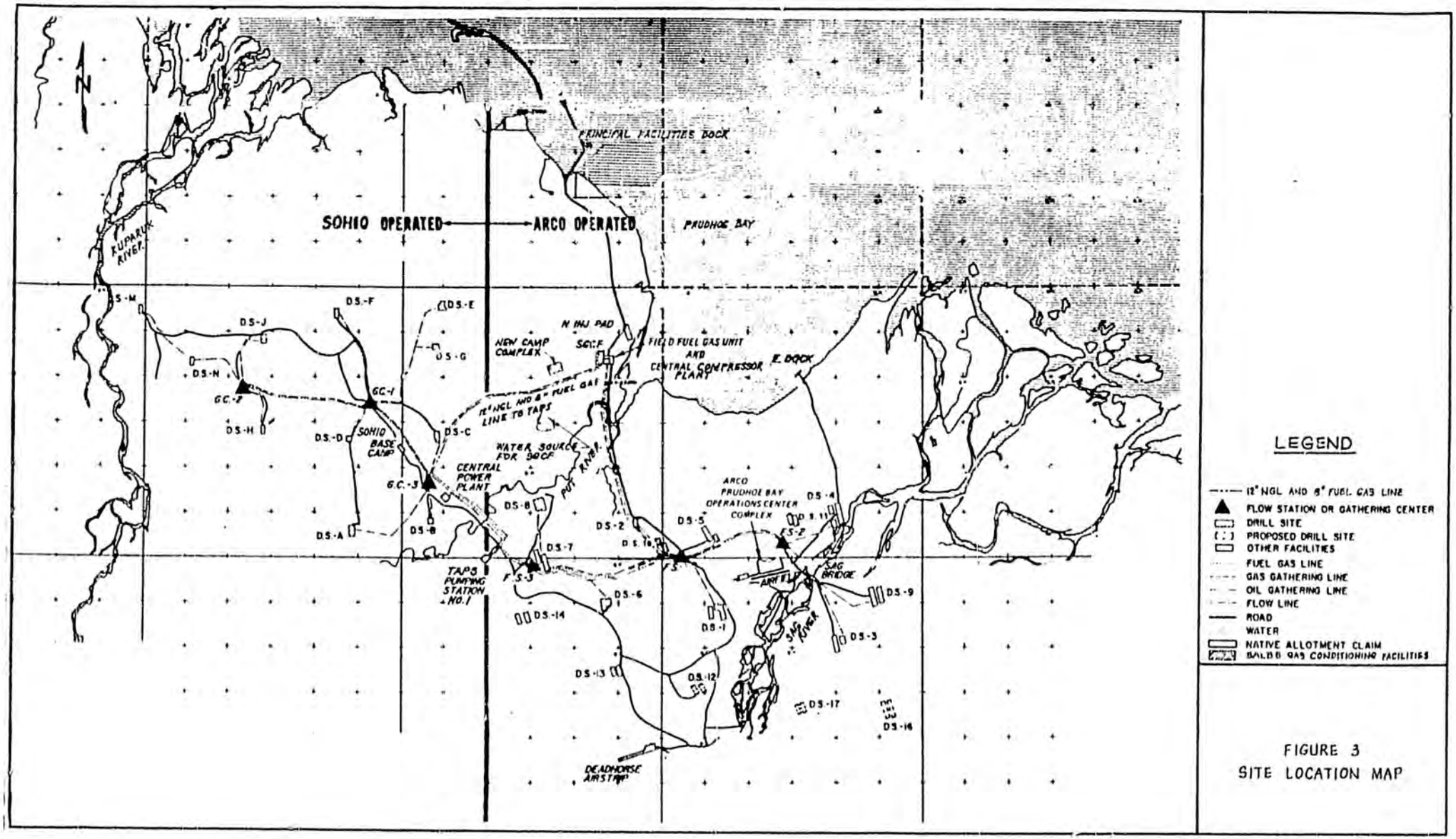


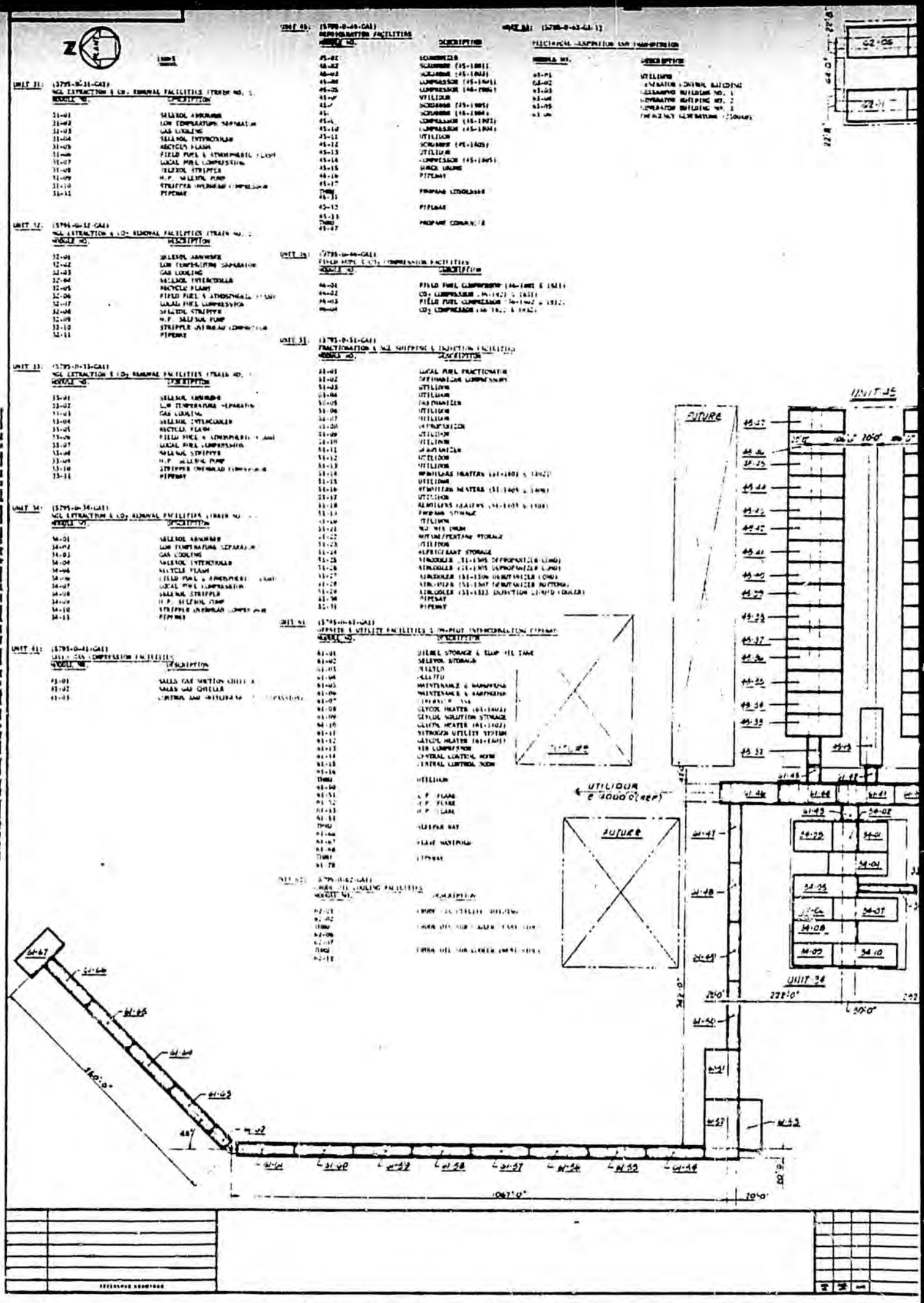
Figure 2
Simplified Process
Flow Diagram – Sales
Gas Conditioning Facilities



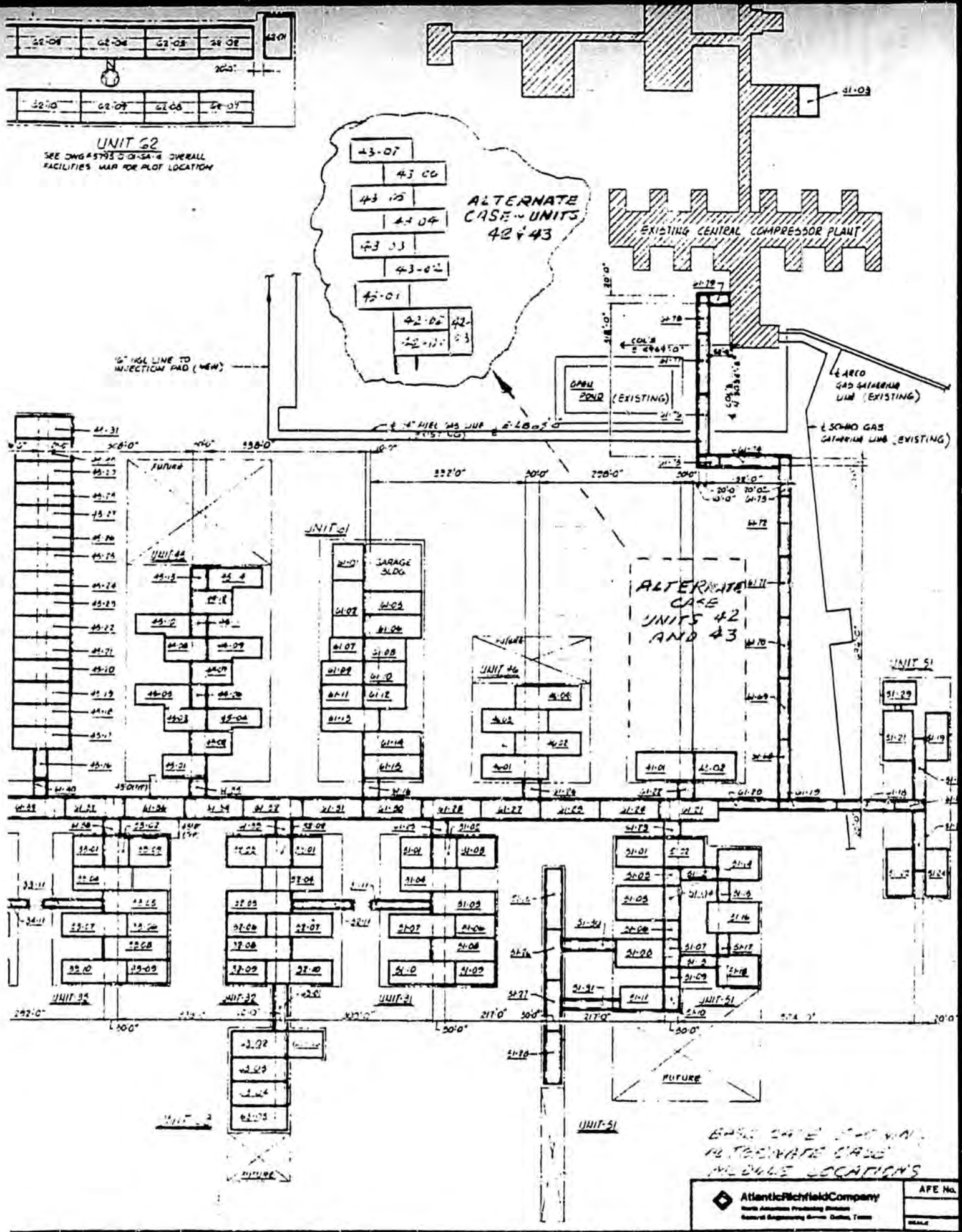
LEGEND

- 12" NGL AND 8" FUEL GAS LINE
- FLOW STATION OR GATHERING CENTER
- DRILL SITE
- PROPOSED DRILL SITE
- OTHER FACILITIES
- FUEL GAS LINE
- GAS GATHERING LINE
- OIL GATHERING LINE
- FLOW LINE
- ROAD
- WATER
- NATIVE ALLOTMENT CLAIM
- BALDB GAS CONDITIONING FACILITIES

FIGURE 3
SITE LOCATION MAP



UNIT 31: (5795-0-31-GA1)
NGL EXTRACTION & CO2 REMOVAL FACILITIES (TRAIN NO. 1)
MODULE NO. DESCRIPTION
31-01 SELEXOL ABSORBER
31-02 LOW TEMPERATURE SEPARATOR
31-03 GAS COOLING
31-04 SELEXOL INTERCOOLER
31-05 RECYCLE FLASH
31-06 FIELD FUEL & ATMOSPHERIC FLASH
31-07 LOCAL FUEL COMPRESSION
31-08 SELEXOL STRIPPER
31-09 H.P. SELEXOL PUMP
31-10 STRIPPER OVERHEAD COMPRESSOR
31-11 PIPEWAY
UNIT 32: (5795-0-32-GA1)
NGL EXTRACTION & CO2 REMOVAL FACILITIES (TRAIN NO. 2)
MODULE NO. DESCRIPTION
32-01 SELEXOL ABSORBER
32-02 LOW TEMPERATURE SEPARATOR
32-03 GAS COOLING
32-04 SELEXOL INTERCOOLER
32-05 RECYCLE FLASH
32-06 FIELD FUEL & ATMOSPHERIC FLASH
32-07 LOCAL FUEL COMPRESSION
32-08 SELEXOL STRIPPER
32-09 H.P. SELEXOL PUMP
32-10 STRIPPER OVERHEAD COMPRESSOR
32-11 PIPEWAY
UNIT 33: (5795-0-33-GA1)
NGL EXTRACTION & CO2 REMOVAL FACILITIES (TRAIN NO. 3)
MODULE NO. DESCRIPTION
33-01 SELEXOL ABSORBER
33-02 LOW TEMPERATURE SEPARATOR
33-03 GAS COOLING
33-04 SELEXOL INTERCOOLER
33-05 RECYCLE FLASH
33-06 FIELD FUEL & ATMOSPHERIC FLASH
33-07 LOCAL FUEL COMPRESSION
33-08 SELEXOL STRIPPER
33-09 H.P. SELEXOL PUMP
33-10 STRIPPER OVERHEAD COMPRESSOR
33-11 PIPEWAY
UNIT 34: (5795-0-34-GA1)
NGL EXTRACTION & CO2 REMOVAL FACILITIES (TRAIN NO. 4)
MODULE NO. DESCRIPTION
34-01 SELEXOL ABSORBER
34-02 LOW TEMPERATURE SEPARATOR
34-03 GAS COOLING
34-04 SELEXOL INTERCOOLER
34-05 RECYCLE FLASH
34-06 FIELD FUEL & ATMOSPHERIC FLASH
34-07 LOCAL FUEL COMPRESSION
34-08 SELEXOL STRIPPER
34-09 H.P. SELEXOL PUMP
34-10 STRIPPER OVERHEAD COMPRESSOR
34-11 PIPEWAY
UNIT 41: (5795-0-41-GA1)
SALES GAS COMPRESSION FACILITIES
MODULE NO. DESCRIPTION
41-01 SALES GAS SUCTION CHILLER
41-02 SALES GAS CHILLER
41-03 CONTROL AND [illegible]
UNIT 45: (5795-0-45-GA1)
REFRIGERATION FACILITIES
MODULE NO. DESCRIPTION
45-01 ECONOMIZER
45-02 SCRUBBER (45-1801)
45-03 SCRUBBER (45-1803)
45-04 COMPRESSOR (45-1801)
45-05 COMPRESSOR (45-1803)
45-06 UTILIDOR
45-07 SCRUBBER (45-1805)
45-08 SCRUBBER (45-1804)
45-09 COMPRESSOR (45-1803)
45-10 COMPRESSOR (45-1804)
45-11 UTILIDOR
45-12 SCRUBBER (45-1805)
45-13 UTILIDOR
45-14 COMPRESSOR (45-1805)
45-15 SURGE DRUMS
45-16 PIPEWAY
45-17 THRU 45-31 PROPANE CONDENSER
45-32 PIPEWAY
45-33 THRU 45-47 PROPANE COMMUNITY
UNIT 46: (5795-0-46-GA1)
FIELD FUEL & CO2 COMPRESSION FACILITIES
MODULE NO. DESCRIPTION
46-01 FIELD FUEL COMPRESSOR (46-1801 & 1821)
46-02 CO2 COMPRESSOR (46-1821 & 1831)
46-03 FIELD FUEL COMPRESSOR (46-1802 & 1812)
46-04 CO2 COMPRESSOR (46-1822 & 1832)
UNIT 51: (5795-0-51-GA1)
FRACTIONATION & NGL SHIPPING & INJECTION FACILITIES
MODULE NO. DESCRIPTION
51-01 LOCAL FUEL FRACTIONATOR
51-02 DEFINANIZER COMPRESSOR
51-03 UTILIDOR
51-04 UTILIDOR
51-05 DEFINANIZER
51-06 UTILIDOR
51-07 UTILIDOR
51-08 DEPROPANIZER
51-09 UTILIDOR
51-10 UTILIDOR
51-11 DEBUTANIZER
51-12 UTILIDOR
51-13 UTILIDOR
51-14 REBOILERS HEATERS (51-1401 & 1402)
51-15 UTILIDOR
51-16 REBOILERS HEATERS (51-1405 & 1406)
51-17 UTILIDOR
51-18 REBOILERS HEATERS (51-1407 & 1408)
51-19 PROPANE STORAGE
51-20 UTILIDOR
51-21 NGL MIX DRUM
51-22 BUTANE/PENTANE STORAGE
51-23 UTILIDOR
51-24 REFRIGERANT STORAGE
51-25 AIRCOOLER (51-1305 DEPROPANIZER COND)
51-26 AIRCOOLER (51-1305 DEPROPANIZER COND)
51-27 AIRCOOLER (51-1306 DEBUTANIZER COND)
51-28 AIRCOOLER (51-1307 DEBUTANIZER BOTTOMS)
51-29 AIRCOOLER (51-1313 INJECTION LIQUID COOLER)
51-30 PIPEWAY
51-31 PIPEWAY
UNIT 61: (5795-0-61-GA1)
OFFSITE & UTILITY FACILITIES & ON-PLOT INTERCONNECTING PIPEWAY
MODULE NO. DESCRIPTION
61-01 DIESEL STORAGE & SLOP OIL TANK
61-02 SELEXOL STORAGE
61-03 UTILIDOR
61-04 UTILIDOR
61-05 MAINTENANCE & WAREHOUSE
61-06 MAINTENANCE & WAREHOUSE
61-07 [illegible]
61-08 GLYCOL HEATER (61-1403)
61-09 GLYCOL SOLUTION STORAGE
61-10 GLYCOL HEATER (61-1402)
61-11 NITROGEN UTILITY SYSTEM
61-12 GLYCOL HEATER (61-1401)
61-13 AIR COMPRESSOR
61-14 CENTRAL CONTROL ROOM
61-15 CENTRAL CONTROL ROOM
61-16 THRU 61-50 UTILIDOR
61-51 H.P. FLARE
61-52 H.P. FLARE
61-53 H.P. FLARE
61-54 THRU 61-66 SLEEPER WAY
61-67 FLARE MANIFOLD
61-68 THRU 61-78 PIPEWAY
UNIT 62: (5795-0-62-GA1)
CROSS OIL COOLING FACILITIES
MODULE NO. DESCRIPTION
62-01 CROSS OIL UTILITY BUILDING
62-02 THRU 62-06 CROSS OIL SUB COOLER (EAST SIDE)
62-07 THRU 62-11 CROSS OIL SUB COOLER (WEST SIDE)
UNIT 45
FUTURE
UTILIDOR
FUTURE
UNIT 34
1067'0"



AtlanticRichfieldCompany
North American Producing Division
General Engineering Group - Dallas, Texas

AFE No.

SCALE

PRUDHOE FACILITIES PROJECT - PRUDHOE BAY, ALASKA

OVERALL MODULE INDEX PLAN
SALES GAS CONDITIONING FACILITIES

THE RALPH M. PARSONS COMPANY
Pasadena

FIGURE 4

FIGURE 5

SALES GAS CONDITIONING FACILITIES

IMPLEMENTATION PLAN

MILESTONE SCHEDULE

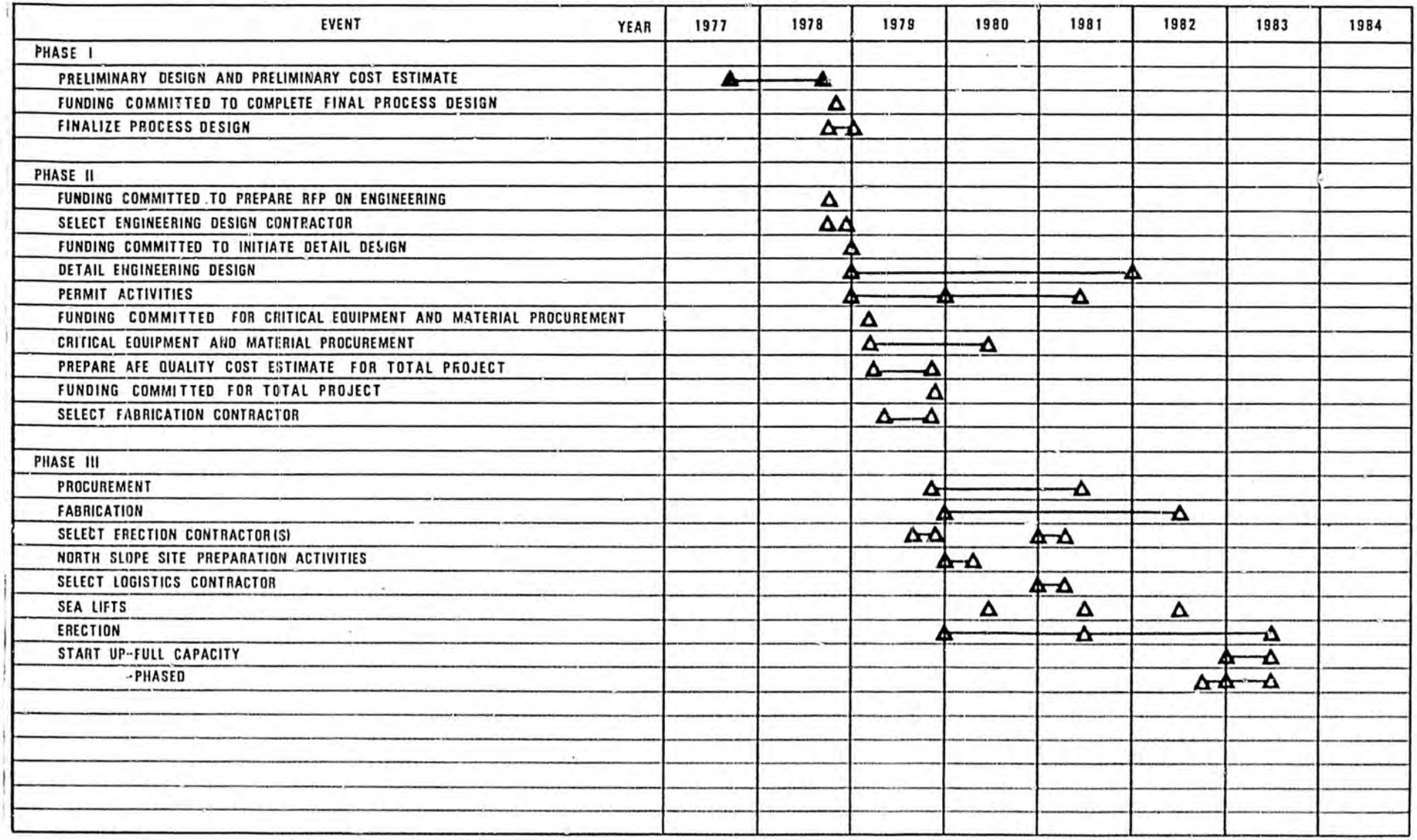
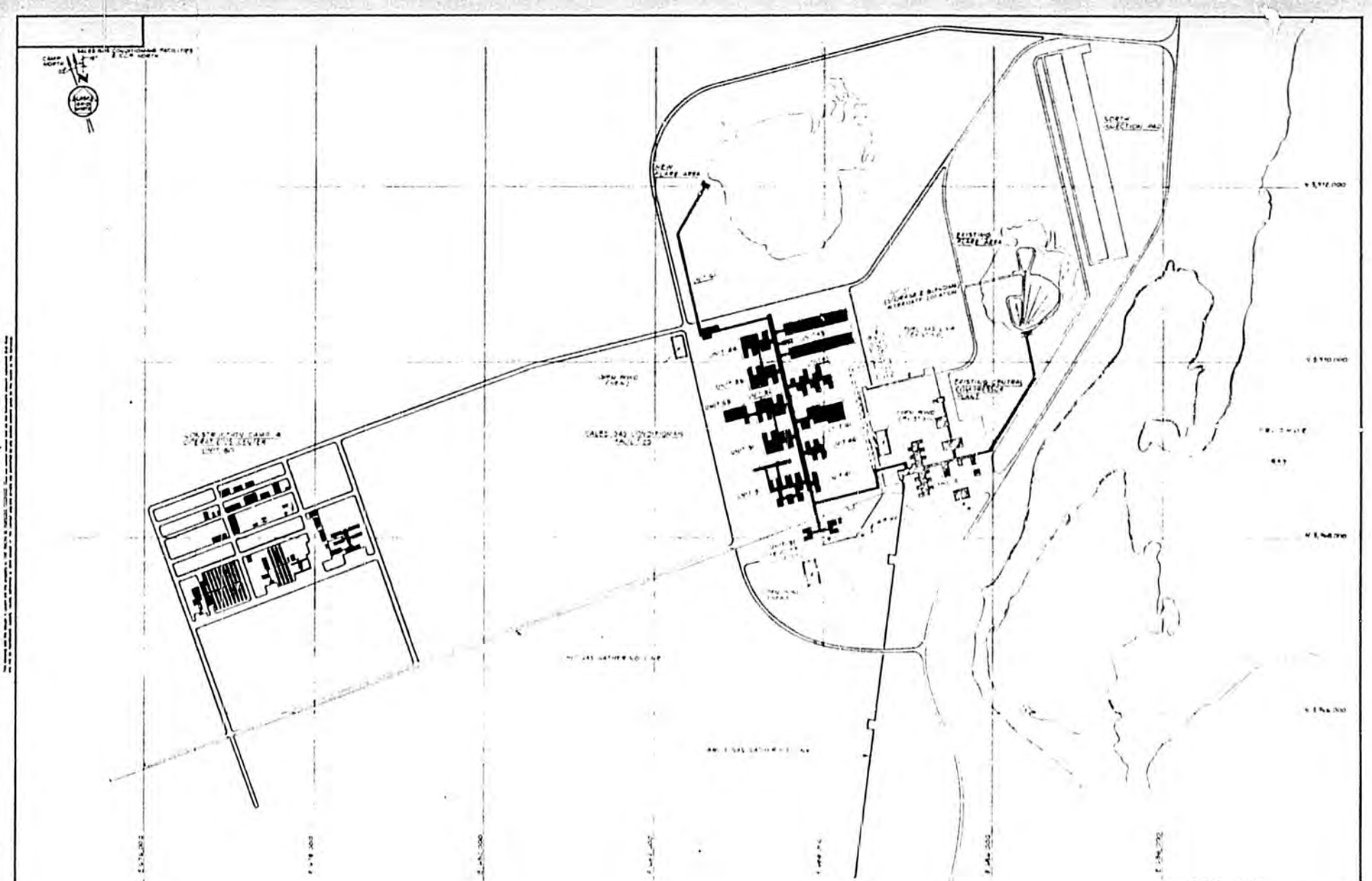
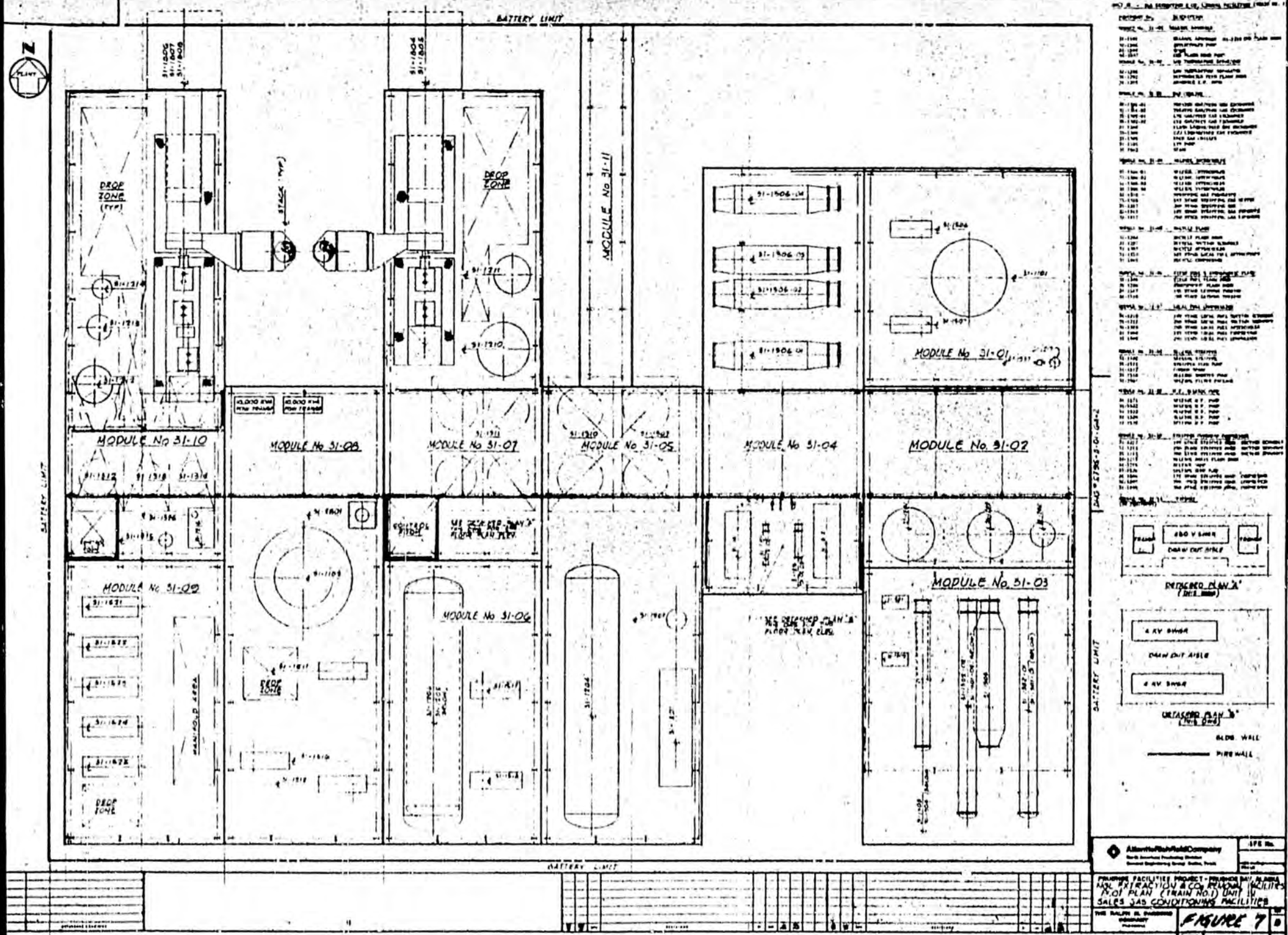
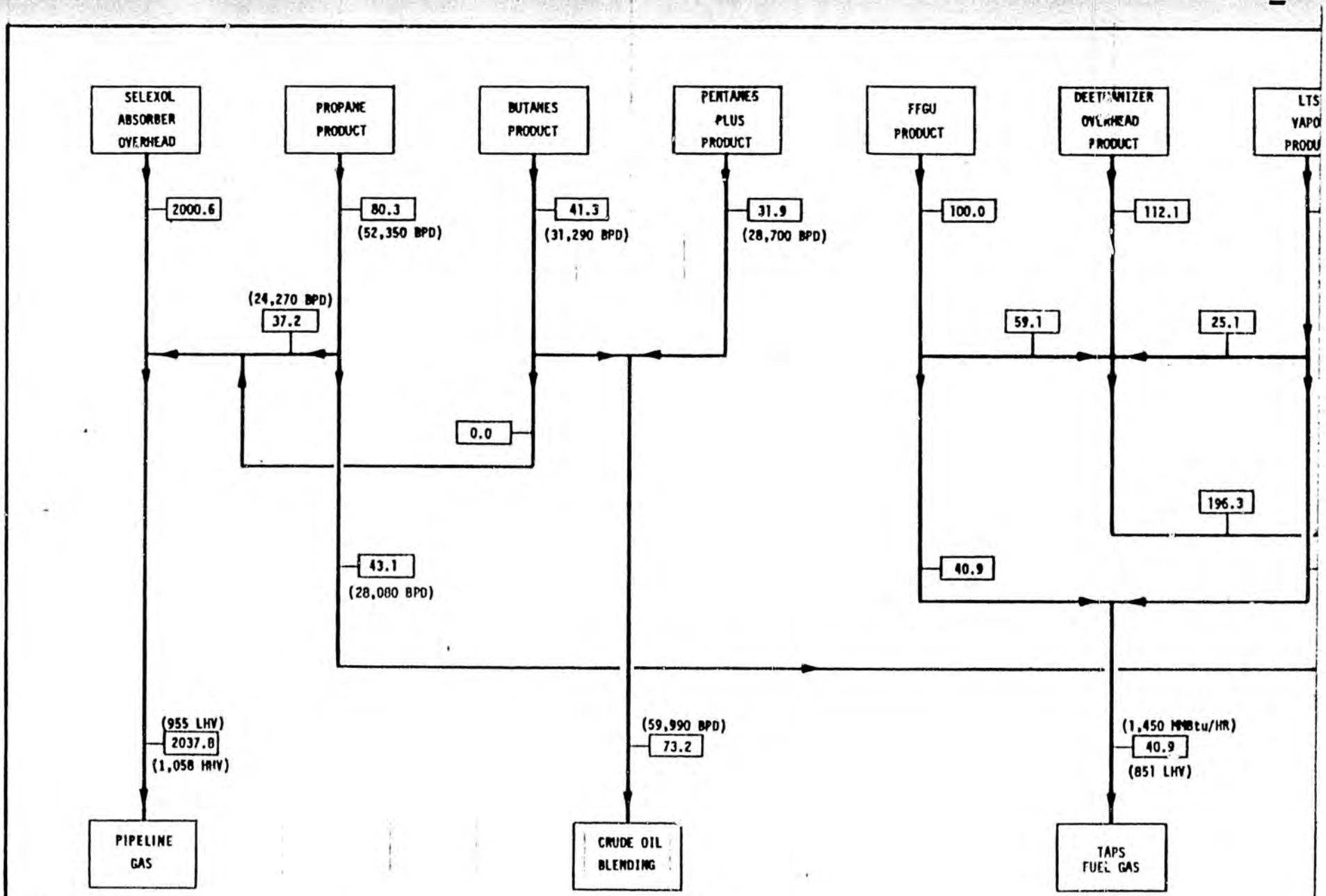
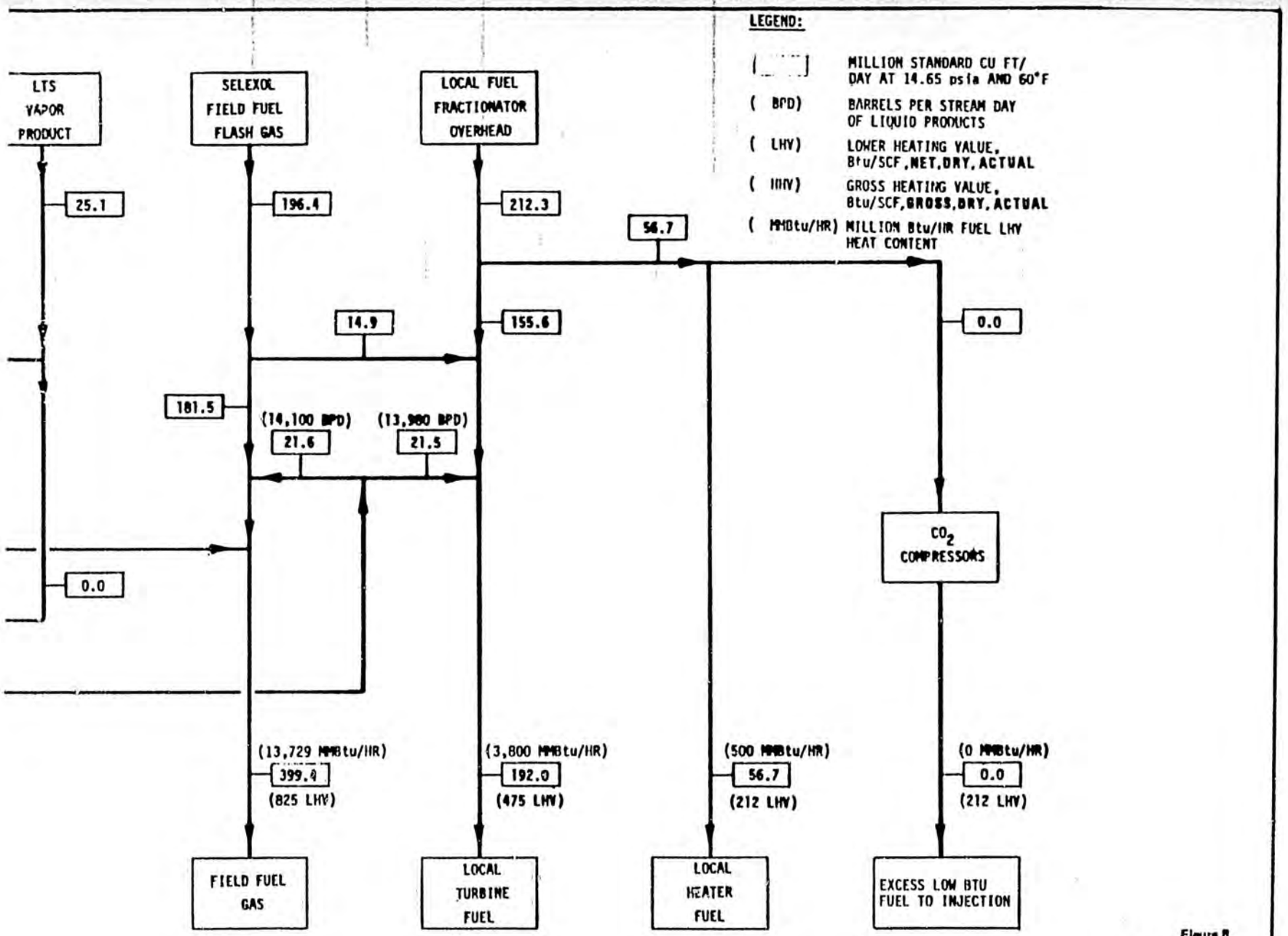


FIGURE 5


BASE CASE
AtlanticRichfieldCompany
PRUDHOE FACILITIES PROJECT - PRUDHOE BAY, ALASKA
SITE PLAN
SALES GAS CONDITIONING FACILITIES
THE RALPH M. PARSONS COMPANY
FIGURE 6


BATTERY LIMIT
DROP ZONE (TYP)
STACK (TYP)
MODULE No 31-11
MODULE No 31-10
MODULE No 31-08
MODULE No 31-07
MODULE No 31-05
MODULE No 31-04
MODULE No 31-02
MODULE No 31-01
MODULE No 31-09
MODULE No 31-06
MODULE No 31-03
MANIFOLD AREA
CONTROL PITCH
DRAW OUT AISLE
DETACHED PLAN 'A'
DETACHED PLAN 'B'
BLDG. WALL
FIRE WALL
AtlanticRichfieldCompany
PRUDHOE FACILITIES PROJECT - PRUDHOE BAY, ALASKA
NGL EXTRACTION & CO2 REMOVAL FACILITIES
PLOT PLAN (TRAIN NO.1) UNIT 31
SALES GAS CONDITIONING FACILITIES
THE RALPH M. PARSONS COMPANY
FIGURE 7


SELEXOL ABSORBER OVERHEAD
PROPANE PRODUCT
BUTANES PRODUCT
PENTANES PLUS PRODUCT
FFGU PRODUCT
DEETHANIZER OVERHEAD PRODUCT
LTS VAPOR PRODUCT
2000.6
80.3
(52,350 BPD)
41.3
(31,290 BPD)
31.9
(28,700 BPD)
100.0
112.1
(24,270 BPD)
37.2
59.1
25.1
0.0
196.3
43.1
(28,080 BPD)
40.9
(955 LHV)
2037.8
(1,058 HHV)
(59,990 BPD)
73.2
(1,450 MMBtu/HR)
40.9
(851 LHV)
PIPELINE GAS
CRUDE OIL BLENDING
TAPS FUEL GAS



EXAMPLE CASE (SEE SECTION 8)

Figure 8
Block Flow Diagram
Of Product And Fuel
Gas Blending

(ESCALATED DOLLARS)

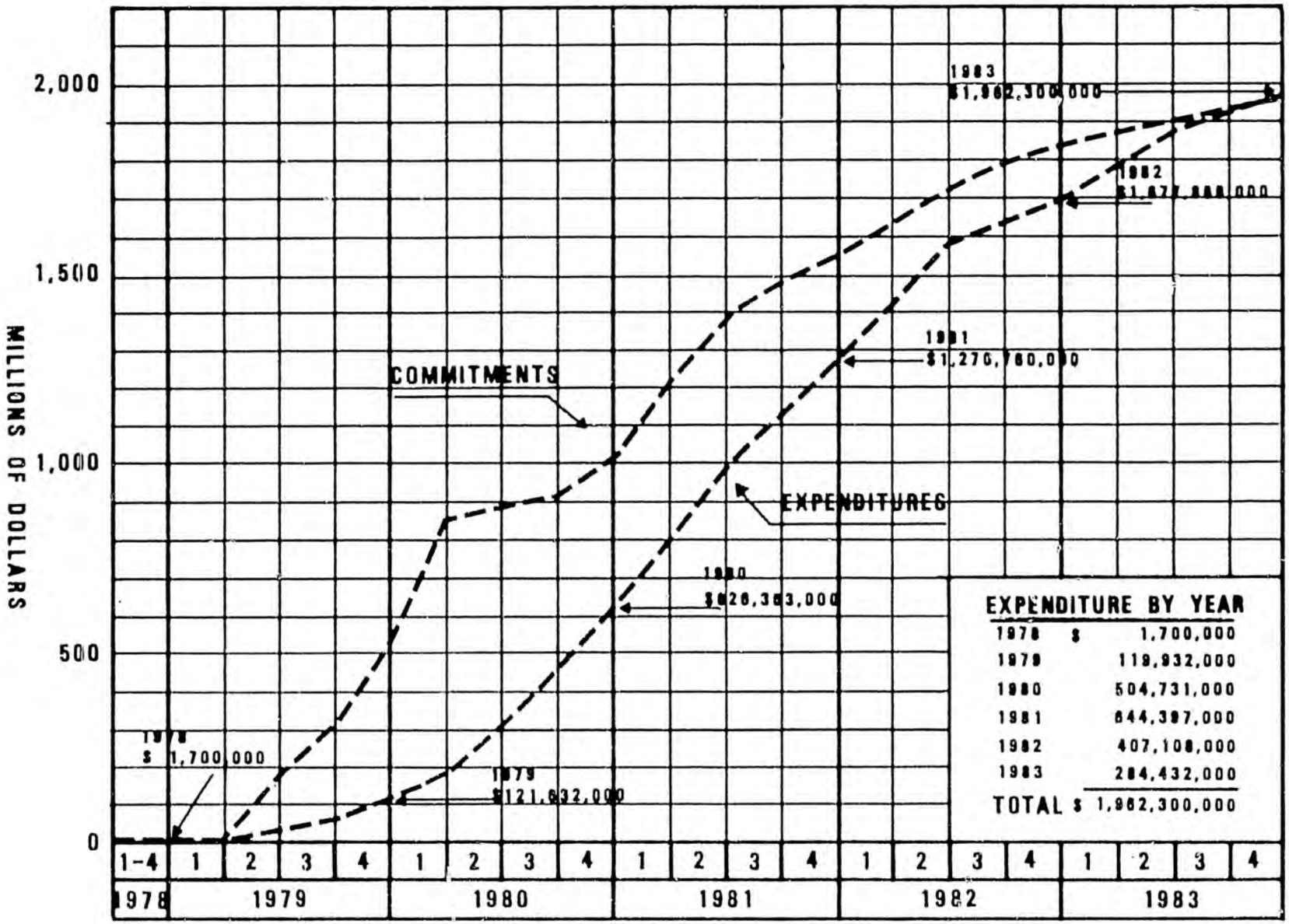


FIGURE 9
SALES GAS CONDITIONING FACILITIES
PATTERN OF COMMITMENTS AND EXPENDITURES
(BASE CASE - FULL-CAPACITY STARTUP)

BMP

SCOMM

#14:13

PRUDHOE BAY NATURAL GAS LIQUIDS, THE ALASKA HIGHWAY GAS PIPELINE, AND PETROCHEMICAL DEVELOPMENT IN ALASKA

A Review of the November 1, 1979 Report,

PROMOTION AND DEVELOPMENT
OF THE
PETROCHEMICAL INDUSTRY IN ALASKA

by Bonner & Moore Associates, Inc.

to the

Alaska Department of Natural Resources
Royalty Oil and Gas Development Advisory Board

By CONNIE C. BARLOW
ARLON R. TUSSING AND ASSOCIATES, INC.

20 January, 1980

CONTENTS

FOREWORD BY ARLON R. TUSSING. ii

I. INTRODUCTION AND SUMMARY. 1

II. DESCRIPTION OF THE PROPOSED PROJECT 4

III. IMPACT OF THE PROJECT ON NORTH SLOPE OPERATIONS 6

IV. EFFECTS OF THE PROJECT ON NORTH SLOPE GAS PURCHASERS AND ON UNITED STATES NET ENERGY SUPPLY. 8

V. EXCHANGING STATE ROYALTY METHANE FOR NATURAL GAS LIQUIDS. 11

VI. FINANCING THE PROPOSED FACILITIES 13

VII. SITING CONSIDERATIONS 15

VIII. ECONOMICS OF PETROCHEMICALS MANUFACTURING IN ALASKA . . . 17

Qualitative outlook 17

Quantitiative outlook 18

The need for a subsidy 21

TABLE 1. THE AVAILABILITY OF LIQUIDS FOR SHIPMENT THROUGH TAPS, THE GAS PIPELINE, OR A GAS LIQUIDS LINE 24

TABLE 2. THE EFFECT OF THE BONNER & MOORE STRATEGY ON THE VOLUME AND RICHNESS OF GAS AVAILABLE FOR TRANSPORT THROUGH THE GAS PIPELINE. 25

TABLE 3. THE PROSPECTS FOR A SWAP OF STATE ROYALTY METHANE FOR PRODUCER-OWNED GAS LIQUIDS. 26

Inquiries about this review should be addressed to:

Connie C. Barlow
Arlon R. Tussing and Associates, Inc.
811 Basin Road
Juneau, Alaska 99801
(907) 586-3930, or

Arlon R. Tussing and Associates, Inc.
2720 Rainier Bank Tower
Seattle, Washington 98101
(206) 447-0321

FOREWORD BY ARLON R. TUSSING

This review began as a private memorandum Connie Barlow wrote at my request for members of our organization and a few professional colleagues. In it she summarized the November 1979 report of Bonner & Moore Associates, Inc. (B&M) to the State of Alaska on the outlook for establishing a new in-state petrochemicals industry based upon natural gas liquids from Prudhoe Bay. She also related B&M's findings to the most controversial current policy issues regarding the disposition of the various North Slope hydrocarbons.

Ms. Barlow's reading of B&M was in startling contrast to the things we had heard about their report. Instead of setting out a strategy for assuring the feasibility of a gas liquids-based petrochemical facility, their analyses seemed to add up to a powerful case against the very development strategy they describe.

The issues involved are of great importance to Alaska, but they are also exceedingly complicated. The B&M report, moreover, is often obscurely written and many --- if not most --- of its key assumptions and sources are unstated. All these considerations argued for a wider distribution of Ms. Barlow's review; but they also demanded an especially careful verification of her interpretation of B&M, and careful editing of any public version.

We sent drafts of this paper to B&M for comment, and also to their subcontractor Birch, Horton, Bittner, and Monroe; to the major Prudhoe Bay gas producers; to Northwest Alaskan Pipeline Company; and to a number of state and federal officials concerned with North Slope oil and gas production, the gas pipeline, and petrochemicals development.

The time my cover letter allowed for response to the review draft did not allow all of these parties to scrutinize it with the thoroughness the review's author gave the B&M report. We did, nevertheless, receive expert and helpful comments from several industry and governmental sources. A group of executives and engineers from one of the producing companies deserves special thanks for spending a day with Ms. Barlow and me, helping to clarify our understanding of the relationships among a number of physical and engineering principles, Prudhoe Bay hydrocarbon balances, and the Parsons design for a North Slope gas conditioning facility.

The basic understandings in Ms. Barlow's first memorandum stood up very well under this intensive review process. We have changed a few numbers and made some editorial improvements, but the thrust of the original review remains intact: B&M do not state a case in favor of gas liquids-based petrochemical manufacturing in Alaska, but rather a case against it.

Neither the B&M report nor the Barlow review is the last word on this issue. Another strategy and another analysis may well demonstrate the feasibility of some kind of petrochemicals venture in the state --- but B&M have not yet presented such a strategy or analysis.

This review is offered to Alaskans as a public service of Arlon R. Tussing and Associates, Inc. It was not produced under contract to, or with funding from, the state of Alaska or any other interested party.

I. INTRODUCTION AND SUMMARY

Bonner & Moore Associates, Inc. (B&M) in November 1979 submitted a report titled Promotion and Development of the Petrochemical Industry in Alaska to the Alaska Department of Natural Resources, Royalty Oil and Gas Development Advisory Board. In the coming year, state officials, legislators, and individual Alaskans will surely cite this study in support of or opposition to proposals for state action to create a local petrochemicals industry using natural gas liquids from Prudhoe Bay.

Unfortunately, the B&M report does not set out its major findings clearly and systematically in any one place, nor does it relate these findings explicitly to the policy issues that have caused the greatest concern or controversy among various Alaskan groups, the North Slope gas producers, the gas pipeline sponsors, and federal agencies. Even more unfortunately, B&M's executive summary will badly mislead any reader who does not read the entire report carefully and critically.

For these reasons, this review is designed, in part, to point out the policy significance of B&M's analyses. We have generally chosen to overlook any disagreements we may have with the report's assumptions and analytical methods --- because even if B&M's calculations are accepted at face value, their logical implications dramatically contradict the executive summary's "affirmative conclusion that a project can be developed in Alaska that would produce ethylene-based petrochemicals for the Pacific market with acceptable profitablity".[emphasis added]

Our review also examines the effects of the B&M scenario on various parties with an interest in the Alaska Highway gas pipeline. While an analysis of these impacts was not clearly part of B&M's study mandate, the costs imposed on other interests by removing natural gas liquids from the sales gas may well be tossed back into the lap of the party that receives the liquids. Some of these effects are substantial, and therefore demand close attention from policy-makers who would look to B&M for practical guidance.

Some of the most important implications that this review draws from B&M's analysis are the following:

*** The B&M scenario requires a change in the gas conditioning process and field fuel design at Prudhoe Bay. Not only would this change negate the Parsons' design and require a whole new conditioning study, but the end result may substantially raise the cost of gas conditioning.

*** Removing 107,000 barrels of natural gas liquids per day from the hydrocarbon stream destined for the Alaska Highway gas pipeline would increase the unit transportation costs of the remaining gas by about 16 percent. The heating value of the gas stream would fall from 1106 to 1050 (gross) BTU per cubic foot.

*** As much as one-fifth of the total energy available to the nation from Prudhoe Bay natural gas could well be lost if a project like that suggested by B&M is put into effect.

*** In order to secure the volume of gas liquids required by the B&M strategy, Alaska could earmark all of its royalty gas liquids, and swap all of its royalty gas (methane) for gas liquids owned by the producers; but the project would still be substantially short of its required volumes.

*** Unless something happens to cause a radical improvement in the economics of the petrochemicals venture described by B&M, their own analysis indicates that it can not operate profitably and pay the state of Alaska anything at all for the ethane it requires as feedstock. In B&M's base case the state would be required to subsidize the project by the equivalent of at least 36 percent (63 cents per MMBTU in 1979 dollars) of its entire Prudhoe Bay royalty gas income.

II. DESCRIPTION OF THE PROPOSED PROJECT

The Bonner and Moore Associates, Inc. (B&M) report, Promotion and Development of the Petrochemical Industry in Alaska, considers the logistics and economics of using North Slope natural gas liquids as feedstocks for a new petrochemicals manufacturing plant to be built in Alaska. In order to perform a detailed analysis the report "creates a 'for instance' project embodying generally conservative premises . . ."[1] The B&M strategy entails:

*** construction of a natural-gas-liquids pipeline from Prudhoe Bay to Cook Inlet,

*** to carry roughly 25 percent (25 thousand barrels per day) of the ethane (C_2) produced from the Prudhoe Bay reservoir,

*** for use as feedstock in a world-scale petrochemicals manufacturing plant near Kenai that would produce about 1 billion pounds of ethylene per year,

*** which the plant would process further into four basic liquid petrochemicals --- low- and high-density polyethylene, ethylene dichloride, and vinyl chloride,

*** for export to Japan, where final processing would take place.

Incidental to the transportation of ethane and manufacture of petrochemicals, B & M propose that:

*** the natural gas liquids pipeline carry almost all of the propane (C_3) and butanes (C_4) separated from the methane (C_1) during natural gas conditioning,

---

1) Joe Moore, letter to Iussing [January 4, 1980].

*** for export as LPG (liquefied petroleum gas) into world markets

The functions of these latter activities, which are not part of the petrochemical operation in itself, are:

*** to provide a greater throughput volume for the natural-gas-liquids pipeline, thus reducing transport costs for ethane, and possibly

*** to cushion petrochemical marketing risks with profits from LPG sales.

III. IMPACT OF THE PROJECT ON NORTH SLOPE OPERATIONS

The B & M report states that its petrochemical development strategy would require two modifications in the present plans for gas processing and conditioning on the North Slope: (1) addition of an ethane extraction facility, and (2) a change in the fuel mix for field operations.

The first modification adds a facility on the North Slope to extract 25 thousand barrels of ethane per day from the roughly 60 thousand barrels that would remain in the "sales gas" stream after conditioning.[2] Quite rightly, the B & M report assumes that the costs of ethane extraction would be borne entirely by the liquids purchaser(s), and thus should impose no direct cost burdens either on the gas producers or on the purchasers of sales gas shipped through the Alaska Highway gas pipeline.

The report, however, does not acknowledge the full impacts of its petrochemical strategy on North Slope fuel availability and overall conditioning design. The conditioning plan now under consideration (the Ralph M. Parsons study) anticipates that the ethane-CO_2 "waste-gas" mixture generated during the conditioning process can be used for fuel if it is further enriched by adding more than half of the propane that the fractionation plant will make available.

---

2) While shipping all 60 thousand barrels per day of available ethane through the gas liquids line could further reduce unit costs of transportation, the report indicates that the cost of high pressure facilities for storage of ethane in liquid form would offset any transportation cost savings. [p. 7-1]

The B & M strategy, however, calls for shipping all of the separated propane through the gas-liquids pipeline. (See Table I.) Accordingly, the report assumes that "field gas" will be used as fuel instead. [p. 3-9] (We assume that field gas is the methane-rich raw gas, less the heavier NGLs and water.)

This change in fuel composition inevitably demands a change in design for the entire conditioning process: Unless propane is available, there is no practical way to enrich the ethane-CO_2 waste gas mixture; hence, a conditioning process that fully removes all hydrocarbons from the CO_2 stream would have to be used.

Such a modification would require a completely new engineering study and might well result in higher overall gas conditioning costs. The B & M report does not acknowledge any such additional costs, and consequently, makes no provision for allocating them to the responsible party --- that is, the petrochemical operation.

IV. EFFECTS OF THE PROJECT ON NORTH SLOPE GAS PURCHASERS AND ON UNITED STATES NET ENERGY SUPPLY

If almost half the ethane and all of the propane and butanes were removed from the sales gas stream shipped through the Alaska Highway gas pipeline, the total caloric value of the gas would be reduced substantially. Gas purchasers would suffer both the effects of (1) a leaner gas stream (fewer BTU per MCF), and (2) higher transportation costs per unit of gas. Export of the petrochemicals from the United States, and possibly of the LPGs as well, would result in (3) a net reduction in domestic U.S. energy supply, which would have to be offset by an increase in crude oil imports.

Table I shows the approximate volumes and BTU content of the hydrocarbons (1) fed into the conditioning plant, (2) consumed as fuel for gas production and conditioning, and (3) available for shipment from the North Slope through the TAPS oil pipeline, the Alaska Highway gas pipeline, or some other transportation facility like the gas liquids pipeline proposed by B&M.

Table II shows how the B & M strategy for petrochemical development would affect the composition and volume of the sales gas, and thereby its market quality and unit costs of transportation through the gas pipeline.

B & M's scenario would reduce the gross heating value of the sales gas from 1106 to 1050 BTU per cubic foot. While 1050 may approach the minimum BTU richness specifications for Lower 48 pipelines, this heating value reduction in itself poses no real threat to gas marketability.

However, the B & M scenario would reduce the total energy content of the sales gas by about 386 billion BTU per day, or 17 percent. The fixed costs and total costs per BTU for pipeline transportation would thus increase by about 20 percent and 16 percent respectively.[3] This is a significant increase, and federal regulators may well be moved to consider allocating those cost increases to the responsible party -- the liquids purchaser(s).

Of the total energy removed from the gas pipeline, 68.5 billion BTU per day in the form of ethane would be converted into non-fuel petrochemicals for export to Japan. B & M are vague about LPG markets, but if these liquids too were exported, the entire 386 billion BTU per day would be a net loss of domestic energy to the U.S. economy. To this total must be added fuel for the ethane extractor and the petrochemicals complex. At least part of this demand would be met by hydrocarbons that otherwise would have reached the Lower 48 as natural gas or crude oil. Unfortunately, B & M do not give us figures on the amount of energy these facilities would require.

If chlorine --- a necessary ingredient in two of the four petrochemicals the plant is to produce --- were manufactured in Alaska, both steam and electricity would be needed. Here, we can at least impute energy demand from the B & M report: 60 billion BTU per day.[4] Altogether, it is conceivable that this project might reduce the total volume of Alaska energy available to the United States as natural gas or crude oil more than 500 billion BTU per day --- over one fifth of the energy the gas pipeline would otherwise contribute.

---

3) These figures are for the entire pipeline system, excluding Northern Border. An 17 percent reduction in BTU shipments corresponds to a 13 percent reduction in MCF. The result would reduce total compressor fuel use by 23 percent in Alaska and 13 percent in Canada.

4) $143,200/day @ $195/ton = 735 tons/day;

755 tons/day @ $186/t @ $2.25/MMbtu = 60 billion BTU/day.

V. EXCHANGING STATE ROYALTY METHANE FOR NATURAL GAS LIQUIDS

Under the Prudhoe Bay lease contracts, the state owns a one-eighth royalty interest in each of the two streams of hydrocarbons (oil and gas) produced from the lease, and may elect to take its royalty either in money or in kind. If the state takes its natural gas royalty in kind, it has to take one-eighth of <u>each</u> of the produced hydrocarbons --- methane, ethane, propane, butanes, and pentanes-plus --- in such combinations as they come from the processing and conditioning facilities.

The state's share of NGLs available falls short of the B&M NGL requirements by 328 billion BTU per day. For this reason, state officials are negotiating with the gas producers, and with federal agencies that might have some regulatory jurisdiction over the disposition or pricing of Prudhoe Bay natural gas liquids, for an option to <u>exchange the state's royalty share of the methane for</u> sufficient natural gas liquids to provide feedstocks for an Alaska petrochemicals plant.

Is such an exchange feasible? Specifically, will the state have enough royalty methane to obtain the additional barrels of NGLs in a BTU-for-BTU swap? Table III shows that the state could take its entire royalty share of Prudhoe Bay ethane, propane, butanes, and pentanes in kind, and swap its entire royalty share of methane to the gas producers for additional natural gas liquids, and still be 109 MMCF per day short.

In other words, the state would need to control 50 percent more methane than it owns at Prudhoe Bay in order to implement the B & M proposal, even if it disavowed any interest in retaining some pipeline gas for residential and commercial consumption in Alaska communities. Unless the petrochemical company were able to buy sufficient gas liquids directly from the producers to make up the deficit, the state would have to do so in its behalf.

VI. FINANCING THE PROPOSED FACILITIES

The B&M proposal requires construction of three separate facilities:

*** A petrochemicals complex on Cook Inlet with a (1979) capital cost of $931 million,

*** A 16-inch natural gas liquids pipeline from Prudhoe Bay to Kenai with a capital cost of about $687.3 million,[5] and

*** An ethane-extraction facility at Prudhoe Bay with a capital cost of about $58 million.[6]

Under both state and federal law, the gas liquids pipeline would have to operate as a common carrier, providing service to all shippers without discrimination, to the limit of its capacity. As a result, the gas liquids pipeline would actually have to be built with a capacity considerably greater than the 107 thousand barrels per day proposed by B&M, in order to assure the petrochemicals plant it would receive 25 thousand daily barrels of ethane every day over the economic life of the facility.[7]

---

5) The B&M report does not mention the cost or even the diameter of the proposed gas liquids pipeline. We have therefore used a subcontractor's estimate from B&M's earlier report to the state [State of Alaska --- Utilization of Royalty Gas (January 23, 1978)]: Pipe Line Technology, Inc., State of Alaska Feasibility Study of Pipeline Transportation, Royalty Gas and NGL (January, 1978), p. 49. We inflated the 1977 capital cost figure ($574.5 million) from that report to mid-1979 dollars at the rate of increase in the Oil and Gas Journal's pipeline cost index between 1977 and the first quarter of 1979. [O&GJ, November 19, 1979]

6) Nowhere in B&M's report is there a statement of the ethane facility's capital cost. The cost of extracting 25,000 barrels per day, however, is given as $1.03 per barrel of recovered ethane [p. 6-5]. Our figure of $58 million assumes that the $1.03 is composed entirely of fixed costs (return of and to investment), levelized in equal annual installments over 20 years at a 15 percent rate of return on total capital.

B&M conclude that even if Alaska succeeded in attracting a firm to build, own, and operate a petrochemicals plant in the state --- and engage in LPG marketing on the side --- it is unlikely that this firm would also be willing to bear the financing and ownership burdens of the other two facilities.[8] Hence, the state must either (1) make an additional effort to recruit a firm (or firms) to finance and operate the ethane extraction plant and the liquids line, or (2) take on the burdens of financing these two facilities.

---

7) Whenever the total volume of natural gas liquids, LPGs, light refined products such as naphtha and gasoline, and possibly even jet fuel, distillate fuel oil and diesel oil, tendered for shipment exceeded the pipeline's shipping capacity, it would have to acccept shipments by all parties ratably, that is, proportionally to their respective tenders.

   If tariffs on the gas liquids pipeline were to be as low as projected by B&M (less than half the average TAPS tariff), and if a profitable market did exist for North Slope LPGs at Cook Inlet, it is likely that at least some of the producers would seek to ship any of their Prudhoe Bay LPGs (the pentanes-plus, for example) not committed to the petrochemicals firm via the liquids line. If new supplies of LPGs became available from other reservoirs on the North Slope, they might also seek space in the line, while the North Slope topping plant and the North Pole refinery are potential shippers of naphtha or light distillates to the Anchorage area. If the line were designed to carry only 107 MB/d, any of these shipments would displace part of the ethane intended for the petrochemicals plant.

   Neither B&M nor (surprisingly) Birch, Horton, Bittner & Monroe, in their subcontractor report to B&M, Government Controls Affecting Development of an Alaskan Petrochemical Complex using North Slope Natural Gas Liquids Feedstock [August 23, 1979] mentions the common carrier issue.

8) "The total investment costs for a liquids pipeline, extraction equipment, and a petrochemical complex are considered to be too great for a single petrochemical producer to bear, since all these investments are subject to identical market risks and are perhaps two to three times as high as for a petrochemical facility built at an established center." [p. 2-4]

VII. SITING CONSIDERATIONS

Bypassing Fairbanks. While B&M have consistently stated that petrochemical development need not by-pass Fairbanks, it is clear that none of the related facilities absolutely depends upon a Fairbanks location. The scenario chosen by B&M for demonstration purposes, for example, places the exthane extractor in the same location as the Prudhoe Bay gas conditioning and processing facilities, and the petrochemicals complex on Cook Inlet. Hence, Fairbanks would get neither of the facilities that its business and government leaders have so avidly sought.

The report does state, however, that "locating the gas-processing plant at Prudhoe Bay will probably result in higher investment and operating costs than the same facility at Fairbanks." [p. 2-2] B&M do not substantiate this judgment, but they pragmatically suggest that the state gauge the economic feasibility of the liquids project on the basis of the most likely events which, given recent FERC decisions, certainly point to a Prudhoe Bay location for gas conditioning. The report does not address the economics or the practical prospects of locating the petrochemical complex itself in Interior Alaska.

Air quality. The report notes that a petrochemical complex in either Anchorage or the Fairbanks-North Pole area might have difficulties in meeting air-quality standards --- even if natural gas rather than coal were used for plant fuel. While Kenai can probably bear the additional air pollution, federal regulatory standards are not likely to allow both the petrochemical complex and the proposed PAC-Alaska LNG plant to be located there. [p. 4-11][9]

9) Joseph M. Chomski of Birch, Horton, Bittner & Monroe (subcontractors to B&M) has criticized this interpretation of page 4-11, citing language in the Birch et al appendix to B&M's report: "The Kenai area has not used up its air pollutant increment yet, despite several industrial facilities already located in the area. However, there is a proposed LNG facility that could use up the increment and foreclose the petrochemical plant siting option due to air pollutant loading. [letter to Barlow, January 7, 1979 (sic)]" Failing to see any substantive difference between the words of our review draft and the subcontractor's own language quoted above, we have maintained our original wording.

VIII. ECONOMICS OF PETROCHEMICALS MANUFACTURING IN ALASKA

Qualitative outlook. B & M cite two main qualitative factors that might attract a chemical company to Alaska:

1. Relatively stable feedstock prices; more properly, feedstock prices that will rise at a predictable rate, [pp. 2-5 and 8-4], and
2. A large and relatively secure supply of natural gas liquids. [pp. 2-5 and 8-4]

The report cautions, however, that three other factors create special burdens for any prospective Alaska petrochemicals producer:

1. Alaska construction will cost about 1.6 times that of comparable facilities on the U.S. Gulf Coast. [p. 2-4]
2. In order to bring ethane to a Cook Inlet facility, someone must build an ethane extractor at Prudhoe Bay and a gas liquids pipeline the length of Alaska: no prudent company would take on the risks of all three of these investments. [p. 2-4]
3. The total risks of such a project in Alaska are two to three times as high as they would be in an established petrochemicals center. [p. 2-4]

Nevertheless, the B & M report judges that the attractions can be expected to outweigh the special burdens of an Alaska location. Joe Moore, in his January 4 letter, refers to ". . . the obvious and overwhelming economic concern of industry, namely that security of feedstock supply and future feedstock cost escalation are the project planning parameters of greatest importance." The following section examines this contention in further detail.

Quantititative outlook. The B&M report [p. 6-5] calculates the volumes of hydrocarbons required by the Cook Inlet petrochemical complex, and their 1979 dollar prices at the plant entrance, as follows:

	Volume (bbl/day)	Price (¢/gal)	Price (¢/lb)	Total Cost (per day)
Ethane (C_2)	24,713	23.3	7.5	$289,586
Propane (C_3)	57,556	27.9	6.6	674,441
Butanes (C_3)	20,354	31.0	6.5	265,009
Pentanes-plus (C_5+)	4,194	33.6	6.4	59,185

These delivered prices reflect [page 2-3]:

*** $1.75/MMBTU for the Prudhoe Bay gas purchase price.

*** $0.50/MMBTU for CO_2 removal at Prudhoe Bay.

*** $1.03 per barrel for ethane extraction at Prudhoe Bay.

*** $2.94 per barrel for the gas liquids pipeline tariff.

B&M do not reveal how they calculated the costs of ethane extraction or of pipeline transportation for the natural gas liquids, nor the basis for their estimates of petrochemical market values in Japan and on the U.S. West Coast. We, therefore, have no basis for evaluating whether these costs are truly realistic. Nevertheless, even if the values in the report are assumed to be correct, they mean that the cost of ethane delivered to the petrochemicals complex will be too high to permit production of marketable ethane derivatives. For, while B&M calculate the cost of ethane delivered to Cook Inlet at 7.5 cents per pound, the petrochemicals complex could afford to pay only 4.3 cents per pound in order to compete in Japanese markets, and only 4.0 cents to compete on the U.S. West Coast [pp. 8-4 and 8-7].[10]

---

10) B&M's projections of maximum affordable ethane prices are those that would meet current 1979 market prices for ethylene derivatives. [Joe Moore, letter to Tussing, January 4, 1980]

The report offers several possibilities for improving this dismal outlook:

First, if the petrochemicals complex owner were willing to accept a rate of return on total investment of only 7.3 percent in place of the 15 percent assumed in the report, Alaska petrochemicals might be competitive in Japan. With a 6.3 percent rate of return, they might be competitive in the United States. [p 8-7] This hope hardly deserves a second look. If the petrochemicals complex were financed with 75 percent debt at 11.5 percent --- the current rate for high-grade industrial bonds --- any return to total investment less than 8.6 percent would yield a negative rate of return to equity.

Second, if the LPGs delivered to Cook Inlet could be sold at a sufficient profit, the cost of ethane delivered to the petrochemicals plant would be reduced from 7.5 to 6.0 cents per pound. [p. C-3] This is still 40 percent higher than B&M's calculation of the maximum ethane price for penetration of the Japanese market, and 50 percent higher than the maximum price for sales within the U.S.

Hope of offsetting losses on the petrochemical operation with profits from LPG sales seems tenuous at best, in view of B&M's earlier observation about the world market outlook for LPGs: "Although the crude oil situation is tight, ample supplies of natural gas liquids exist . . . With this surplus, the Oil and Gas Journal indicates that the world-wide liquefied petroleum gas (LPG) market may offer unsatisfactory prices for exporters." [p. 3-3]. Nevertheless, B&M maintain that the Alaskan LPG sales can operate profitably: "...our projected price for LPG fully takes into account a future surplus of these materials which deprive them of their premium value experienced in recent years." [Joe Moore, letter to Tussing, January 4, 1980]

B&M touch upon two other possibilities for bridging the gap between maximum economic prices for ethane and its cost to the petrochemicals complex. The report mentions a "significant" prospect for reducing transport costs by backhauling vegetable oils from Japan, but does not elaborate further. [p. 5-2]

Alternatively, if no attempt were made to recover plant investment by means of depreciation, to repay principal and pay interest on borrowed capital, or to capture any return on equity, B&M conclude that the petrochemicals complex could afford to pay 6.5 cents per pound for ethane, rather than 4.3 cents [p. 8-4]. Even this "cash-cost" approach leaves the petrochemical facility with feedstock costs 25 percent higher than B&M indicate it could afford to pay.

Moreover, while the investors in existing facilities (say, in Japan) might have no alternative but to accept a "cash cost" price that covers only feedstock and other operating costs, in order to retain customers in a buyers' market, no prudent management would decide to build a new facility if penetration of the market appeared to require "cash-cost" pricing from the outset.

Finally, if feedstock prices were to rise at an annual rate 3.4 percent higher in Japan than in Alaska, the B&M report concludes that ethylene derivatives produced in Alaska might become competetive in five years [p. 8-7]. Unfortunately, B&M do not explain to their readers how a 3.4 percentage-point differential in annual price escalations would bridge the gap between a value of 4.3 cents and a cost of 7.5 cents in five years.

In addition, the report fails to account for the unusual market penetration barriers likely to exist in Japan, in the form of long-term contracts with joint-venture plants in oil-producing nations, protectionist policies on behalf of Japan's domestic petrochemicals industry, or the discounting of prices below "full costs" --- perhaps as low as "cash costs" --- attendant on a quite plausible world oversupply of ethylene.

Even if the report's conclusions with respect to differential feedstock price escalations are valid, the reader must also consider the economic handicaps noted in this review, which the B&M report did NOT take into consideration.[11] All in all, none of the offsetting features that B&M note seems to be substantial, certain, or realistic enough to persuade any prudent management to invest in Alaska petrochemicals development in the manner suggested by the report, or even to consider it seriously.

The need for a subsidy. Using B&M's base case figures, the only certain way to bring the ethane "cost" at Cook Inlet (7.5 cents per pound) down to the ethane "value" (4.3 cents per pound), would be for the state to pay the liquids purchaser(s) $.90 per MMBTU for the 68.5 billion BTU per day of ethane delivered. If the required subsidy were spread over all of the state's royalty gas and gas liquids from Prudhoe Bay, Alaska would end up with only $1.12 per MMBTU ($318,500) for its share of production, rather than the $1.75 per MMBTU ($500,500) the state would have received each day in revenue from gas shipments through the Alaska Highway pipeline.[12]

---

11) Joe Moore replies that the author of this review " . . . devotes several pages to impacts on the gas pipeline project. We did not treat that subject and I will not comment on it here." [letter to Tussing, January 4, 1980]

Granted, Joe Moore [in his January 4 letter] characterizes the report's contrast between an ethane cost of 7.5 cents and a value of 4.3 cents per pound as a "worst case" example on the ground that those numbers do not reflect any of the offsetting factors he mentions elsewhere. But as we have pointed out, some of these factors do not look particularly promising; these "worst-case" cost calculations, and in addition, wholly fail to take into account the collateral costs (new conditioning design, higher gas pipeline tariffs) that are inescapable if most of the liquids are removed from the sales gas stream.

The preceding calculations, moreover, accept at face value one crucial assumption by B&M which is clearly not the worst case but the best --- namely that the price of hydrocarbons at the tailgate of the conditioning plant, and hence their value in the sales gas stream, will be $1.75 per MMBTU (in 1979 dollars). This figure is in reality an absolutely irreducible and highly improbable minimum.

---

12) Manner of calculation. We imputed the maximum price that the petrochemicals manufacturer can afford to pay for ethane delivered to its plant gate from the ratio between B&M's value and cost figures:

$$\frac{(\$.043)}{(\$.075)} \times (\$1.75 + \$.50 + \$1.03 + \$2.94) = \$3.57 \text{ per MMBTU.}$$

But the irreducible cost of separating the ethane and of transporting the natural gas liquids is:

$\$.50 + \$1.03 + \$2.94 = \$4.47$ per MMBTU.

Hence, even if the petrochemicals manufacturer received the gas at Prudhoe Bay totally free of charge, somebody would have to make up the 90 cent deficit on each MMBTU of the 68.5 billion BTU shipped daily --- a total of $61,600 per day. As the producers are unlikely to sell or exchange their Prudhoe Bay hydrocarbons for any price less than they would have received by shipping them through the gas pipeline (much less pay someone to take them away), the state would have to absorb the entire deficit of $2.65 per MMBTU, or $181,400 per day. In relation to the entire state royalty share of 285,600 billion BTU per day, the implied subsidy would be $0.64 per MMBTU.

While the $1.75 conforms to a preliminary FERC ruling that allocates all conditioning costs to the gas producers, the outstanding gas sales contracts add these costs to the $1.75 wellhead price, and the Department of Energy has asked FERC to withdraw its decision and leave the matter up to negotiations among the parties.[13]

It is not unlikely that the final settlement of this issue will provide for addition of 30 to 50 cents per MMBTU to the sales gas price as a partial allowance for conditioning costs. Using the same methods as above, a 30 cent allowance would increase the cost of the whole 395,800 MMBTU per day --- and also its value as part of the sales gas --- by $118,700, to a total of $811,400 per day. The project's revenue deficit would increase by the same amount, and its economics would be further worsened, to the extent of 42 cents for each of the state's 265,600 MMBTU per day of royalty gas and gas liquids. If FERC should agrees to a conditining cost allowance exceeding 30 cents the project's losses would, of course, be increased proportionally.

---

13) B&M might conceivably be excused for passing over this issue, but it is surprising that the Birch, et al, appendix to the B&M report, which devotes 23 pages to "Government Controls on Natural Gas and Gas Liquids" and "Feedstock Price Controls and Related Issues," makes no mention whatsoever of the current proceedings regarding the allocation of conditioning costs, which can have such a powerful influence on feedstock prices, and thus on the economics of the proposed petrochemicals plant.

TABLE 1. THE AVAILABILITY OF LIQUIDS FOR SHIPMENT THROUGH TAPS, THE GAS PIPELINE, OR A GAS LIQUIDS LINE[1]

HYDRO-CARBON	INLET GAS[2] to conditioning plant	FIELD FUEL[3]	PLANT FUEL[4]	AVAILABLE HYDROCARBONS[5]	B&M LIQUIDS ACQUISITION[6]
C_2	111.4 Mb/d	39.2 Mb/d	14.5 Mb/d	58.1 Mb/d[7]	24.7 Mb/d
C_3	61.8 Mb/d	22.5 Mb/d	16.7 Mb/d	23.3 Mb/d[8]	57.6 Mb/d[8]
C_4(i)	10.3 Mb/d	.8 Mb/d	.3 Mb/d	9.4 Mb/d	none
C_4(n)	23.7 Mb/d	.9 Mb/d	.1 Mb/d	23.3 Mb/d	20.3 Mb/d
C_5(i)	6.2 Mb/d	.1 Mb/d	none	6.3 Mb/d	4.2 Mb/d
C_5(n)	11.4 Mb/d	.1 Mb/d	none	11.7 Mb/d	none
C_{6+}	9.7 Mb/d	none	none	10.2 Mb/d	none
TOTAL	234.5 Mb/d	63.6 Mb/d	31.6 Mb/d	142.3 Mb/d	106.8 Mb/d

1. Unless otherwise noted, these figures reflect the data provided by the Ralph M. Parsons study report, Sales Gas Conditioning Facilities: Prudhoe Bay Alaska, (which assumes 2.0 bcf/day of sales gas with a minimum of 1 percent CO_2). The translation of the Parsons' data into barrels is based on a table prepared by Exxon USA entitled "Material Balance: Prudhoe Bay Conditioning Plant" [undated]. The vertical and horizontal totals are not precisely consistent, and Table 1 reflects those disparities.

2. INLET GAS consists of the total gas production, less volumes removed by the existing Field Fuel Gas Unit (FFGU) for use in the first four TAPS pump stations and for oil-related field activities.

3. FIELD FUEL is a projection of the maximum fuel volume required for waterflood, artificial lift, etc., less the volume of fuel supplied by the existing FFGU, as calculated by Parsons.

4. PLANT FUEL consists of fuel needed for local heaters and local turbines within the conditioning facility.

5. AVAILABLE HYDROCARBONS are the remainder available for shipment through TAPS, a natural gas pipeline, and/or a natural gas liquids line, after field and plant fuel requirements are provided for.

6. B&M LIQUIDS ACQUISITION reflects the data shown on page C-3 of the B&M report. While B&M state that, "All of the propane and heavier liquids are recovered for a total NGL volume of 107,000 B/D," the B&M figures are not consistent with the volumes of avails calculated by Parsons.

7. 53.3 Mb/d of the initial 111.4 Mb/d remains in the CO_2 waste gas stream.

8. Of all hydrocarbons, only propane (C_3) is available in volumes less than B&M propose for acquisition. The deficit is substantial: 23 thousand barrels per day available, in contrast to 58,000 barrels required.

TABLE 2. THE EFFECT OF THE BONNER AND MOORE STRATEGY ON THE VOLUME AND RICHNESS OF GAS AVAILABLE FOR TRANSPORT THROUGH THE GAS PIPELINE

COMPONENT	TOTAL AVAILABLE HYDROCARBONS[1]	(without petrochemicals project) HYDROCARBONS AVAILABLE TO GAS PIPELINE	(with petrochemicals project) HYDROCARBONS AVAILABLE TO GAS LIQUIDS PIPELINE	HYDROCARBONS AVAILABLE TO NATURAL GAS PIPELINE (liquid volume)	(gas volume)	(gross energy)[5]
C_1	1,879 MMCF/d[2]	1,879 MMCF/d	none		1,749 MMCF/d[4]	= 1,766 BBTU/d
C_2	58.1 MB/d	58.1 MB/d	24.7 MB/d	33.4 MB/d	= 53 MMCF/d	= 93 BBTU/d
C_3	23.3 MB/d	23.3 MB/d	57.6 MB/d	none	none	none
C_4(i)	9.4 MB/d	9.4 MB/d	none	9.4 MB/d	= 12 MMCF/d	= 9 BBTU/d
C_4(n)	23.3 MB/d	21.9 MB/d[3]	20.3 MB/d	1.6 MB/d	= 2 MMCF/d	= 7 BBTU/d
C_5(i)	6.3 MB/d	.8 MB/d[3]	4.2 MB/d	none	none	none
C_5(n)	11.7 MB/d	.2 MB/d[3]	none	none	none	none
C_{6+}	10.2 MB/d	none[3]	none	none	none	none
CO_2 + N_2		2.3MMCF/d			2 MMCF/d	
TOTAL VOLUME		2,071 MMCF/d			1,815 MMCF/d	
TOTAL ENERGY[5]		2,291 BBTU/d				1,905 BBTU/d
GAS QUALITY[5]		1,086 BTU/CF			1,050 BTU/CF	

1. AVAILABLE HYDROCARBONS are from Table 1, column 5.

2. 90.71 percent of 2071.

3. Available volumes, less shipments via TAPS.

4. Because 34.3 MB/d of the propane required for field fuel is not available under the B&M scenario, a BTU-equivalent (131 billion BTU per day), presumably methane, must be removed from the hydrocarbons available through the gas pipeline (130 MMCF per day).

5. Heating values are in gross or high heating value (HHV) BTU. All heating value and volumetric conversions are taken from the Gas Processors' Association tables, which we presume are equivalent to those used in the Parsons study.

TABLE 3. THE PROSPECTS FOR A SWAP OF STATE ROYALTY METHANE FOR PRODUCER-OWNED NATURAL GAS LIQUIDS

HYDROCARBONS AVAILABLE TO THE GAS PIPELINE[1]		1/8 STATE ROYALTY SHARE (volume)	1/8 STATE ROYALTY SHARE (energy)	HYDROCARBONS AVAILABLE TO THE GAS LIQUIDS PIPELINE[2] (volume)	HYDROCARBONS AVAILABLE TO THE GAS LIQUIDS PIPELINE[2] (energy)
C_1	1749 MMCF/d[3]	218.6 MMcf/d	220.7 BBTU/d	none	none
C_2	58 MB/d	7.3 MB/d	20.2 BBTU/d	24.7 MB/d	68.5 BBTU/d
C_3	58 MB/d	7.2 MB/d	27.5 BBTU/d	57.6 MB/d	220.3 BBTU/d
C_4(i)	9 MB/d	1.2 MB/d	5.0 BBTU/d	none	none
C_4(n)	22 MB/d	2.7 MB/d	11.7 BBTU/d	20.3 MB/d	87.8 BBTU/d
C_5(i)	1 MB/d	.1 MB/d	.5 BBTU/d	4.2 MB/d	19.2 BBTU/d
C_5(n)	t	none	none	none	none
TOTAL NGLs		18.5 MB/d	464.9 BBTU/d	106.8 MB/d	395.8 BBTU/d
TOTAL HYDROCARBONS			285.6 BBTU/d		395.8 BBTU/d

1. Figures are taken from Table 2, Column 3. (Inlet gas to conditioning plant, less plant and field fuel, less TAPS allocation, in the Parsons plan).

2. Figures are from B&M report, page C-3.

3. Assumes that the 34.3 MB/d of propane no longer available for field and conditioning fuel is replaced by methane. (See note No.4, Table 2.)

Calculation. State royalty liquids fall 330.9 billion BTU/d short of the volume B&M state is necessary to make a gas liquids line profitable. This shortfall is equivalent to 327.7 MMCF of methane; but the state only has 218.6 MMCF per day of royalty methane available to swap for gas-producer-owned liquids. The shortfall in royalty methane, therefore, is 109.1 MMcf/d, or about 50 percent more than the state owns.

SCOMM

#14:14

FILE: TUSSING REPORTS, GASLINE

QUESTIONS AND ANSWERS CONCERNING THE ALASKA HIGHWAY GAS PIPELINE

by ARLON R. TUSSING

NOVEMBER 1979

These questions and answers were originally prepared for an October 1979 appearance by Dr. Tussing at a regulatory proceeding in Canada. This version has been slightly extended and revised for general audiences in Canada and the United States.

1.Q. Dr. Tussing, please state your address and occupation.

A. I have two professional addresses. First, I am adjunct professor of economics in the Institute of Social and Economic Research of the University of Alaska, 707 "A" Street, Anchorage, Alaska. I am also president of Arlon R. Tussing and Associates, Inc., economic consultants, 2720 Rainier Bank Tower, Seattle, Washington.

2.Q. Please briefly describe your education and professional experience.

A. I was graduated with bachelors' degrees from the University of Chicago and Oregon State College, pursued advanced study in economics at the Institute of Economic Research of Hitotsubashi University, Tokyo, and have a doctorate in economics from the University of Washington in Seattle.

I have been affiliated with the University of Alaska on a full- or part-time basis since 1965. In 1967 through 1969 I was staff economist of the Federal Field Committee for Development Planning in Alaska, and from 1972 through 1976 I was chief economist of the U.S. Senate Committee on Interior and Insular Affairs (now the Committee on Energy and Natural Resources).

I have served part-time as a consultant to government and industry since 1976, and about two years ago established a consulting firm based in Seattle. My clients have included agencies of the United States and Canadian federal governments; the states of Alaska, Washington, and California, and the provinces of British Columbia, Ontario, and Nova Scotia; petroleum, utility, and transportation companies; and Alaska Native corporations.

3.Q. You are reputed to have originated the concept of an Alaska Highway gas pipeline. Don Peacock, for example, in his book, People, Peregrines, and Arctic Pipelines, says that the pipeline "*** was the idea of none of the companies involved. It was the brainchild of a professor of economics at the University of Alaska, who was then serving as a consultant to the Senate Committee on Energy and Natural Resources, Dr. Arlen [sic] Tussing. *** He buttonholed Blair during a Washington visit in Febuary 1976 to plead with him to give some serious thought to the idea." The author goes on for several pages about your contribution to the Alcan concept. Are you familiar with Mr. Peacock's book?

A. I am.

4.Q. Is his account accurate?

A. Mr. Peacock is substantially correct about my role in getting Mr. Blair and Foothills involved. But I was by no means the only person in the United States or Canada who had considered an Alaska Highway route for the gas line before 1976. The Mountain Pacific group under the leadership of Westcoast Transmission Company, for example, had begun to study an Alaska Highway proposal in 1970.

5.Q. Please outline the work you did for the Legislative Affairs Agency of the State of Alaska about the financing of the Alaska Highway pipeline.

A. In April 1978, Northwest Alaskan Pipeline Company, the chief American sponsor of the Alaska Highway gas pipeline, proposed that the State of Alaska participate in financing the pipeline segment within its borders. The Alaska Legislature's response to this request included a contract with the University of Alaska's Institute of Social and Economic Research to investigate the economics of the pipeline project, its commercial viability, and the effect (if any) that state investment might have on its chances for success. Under this contract, Connie C. Barlow and I published three reports on the pipeline venture.

6.Q. Could you tell us a little about Ms. Barlow.

A. Connie Barlow is a natural scientist by training, and immediately before joining my firm had served as assistant to the President of the Alaska State Senate, and then as staff assistant to Alaska's Commissioner of Natural Resources, dealing with management of the state's royalty oil and gas.

7.Q. Go on about your reports to the legislature.

The first preliminary report, Marketing and Financing Supplemental Gas, was adapted from earlier work Ms. Barlow and I had done for the U.S. Department of Energy's Office of Oil and Gas Policy. It was released by Alaska's Legislative Affairs Agency on October 25, 1978, along with a primer on natural gas, Introduction to the Gas Industry, which explained what natural gas was and how it was shipped, sold, and regulated. The report found that uncertainty about marketability of Alaska gas was large enough to warrant concern by all parties involved in its production, transportation, and distribution, and particularly by prospective suppliers of debt capital to the pipeline project.

The Alaska Highway Gas Pipeline: A Look at the Current Impasse, released on January 13, 1979, was

the second preliminary report in this series. Reviewing the events that led to the selection of the Alaska Highway route and its present sponsor, our report also examined the claims of Northwest and federal officials that government financial assistance was unneccessary. We concluded that Northwest, the Department of Energy, and the President had put themselves in a box with overly optimistic claims about the outlook for private financing, and that the venture surely would remain at an impasse until the sponsors and the federal government faced up to the matter of risk allocation and devised an honorable retreat from their earlier dogmatic assurances to Congress.

Financing the Alaska Gas Pipeline: What is to be Done? was the final report from this investigation. Published in April, 1979, it concluded that the pipeline was not a viable enterprise as then planned, and that even if Northwest's urgent demand on the State of Alaska for a half billion dollar equity contribution were met, the project would still be unworkable. In light of this finding, the final report concentrated on what had to be done, and by whom, if the project were to have a chance of success.

8.Q. John McMillian, Chairman of Northwest Alaskan, has denounced your report as incompetent, and claims that you and Ms. Barlow never bothered to obtain his views or those of his financial advisors. Before you published your reports, did you in fact make any effort to contact the people in industry and government who are actually involved in planning and financing the project?

A. The economic and financial analyses were our own, but we developed and refined them in the course of interviews with practically everyone connected with the project except Mr. McMillian, who refused to see us. We had interviews with the officers and staff of the three major North slope producing companies and several Canadian producers; a representative cross-section of the U.S. gas transmission and distribution companies, including Northwest's partners in the Alaska project and all of the major Canadian pipeline companies; a host of investment banking firms, including advisors to Northwest (Mr. McMillian to the contrary notwithstanding), and other financial institutions, including the two largest institutional lenders in the United States. We spoke with members and staff of the Federal Energy Regulatory Commission (FERC) abd several state

utility commissions; top officials and analysts at the Department of Energy; members and staff of the United States House of Representatives and Senate, personnel of the Congressional Research Service, the General Accounting Office and the Congressional Budget office. We also consulted with Canadian federal and provincial government officials and staff, including members of the National Energy Board, and the Commissioner and staff of the Northern Pipeline Agency; and with the United States Ambassador and embassy staff.

Before us, Neither Northwest nor the responsible federal officials had bothered to talk to all of the concerned parties, or made any effort to put their respective motives and views into a larger perspective. Now, everybody seems to be communicating with everybody else, and I feel that our interviews and reports helped to initiate the current round of discussions and negotiations.

9.Q. What did you conclude about the economics of the pipeline project? Does it make sense economically?

A. It does. We started from the proposition that the pipeline would be worth building if the value of Alaska gas to consumers in the Lower 48 states were

greater than the real economic cost of delivering it. Real economic cost --- sometimes called resource cost --- means the value of the labour, materials, and capital that would be needed for field development, gas conditioning, and the pipeline system proper. We concluded that Alaska gas would be a bargain for the U.S. economy even with substantial cost overruns on the pipeline, and even if the price of imported oil remained stable at early 1978 prices.

10.Q. Did you conclude, therefore, that marketability of Alaska gas would not be a problem?

A. Marketability is a different issue. Marketability has to do with the price consumers pay, not the real economic cost of the gas. We found that the economic cost of the gas would be less than $2.00 per million btu (in 1978 dollars) over the life of the pipeline. But the price paid by consumers includes not only the cost of labour, materials, and capital, but also oil company profits, state and Native royalties, and state and provincial taxes. We reckoned that the average price of Alaska gas in 1978 dollars could be as high as $4.00.

Pipeline tariffs have their highest charges in the early years, and we saw a possibility --- however

remote --- that the gas might be overpriced at some time during the life of the Alaska Highway system. Northwest and the Federal Energy Department tended to dismiss this possibility, but potential investors in the system --- the insurance companies, for example --- were quite concerned about marketability.

11.Q. What did you conclude, therefore, about the financibility of the pipeline?

A. We concluded that the Alaska Highway Gas Pipeline could not be financed and built unless the United States government guaranteed at least part of the project debt.

12.Q. This conclusion is quite at odds with the views of Mr. McMillian and the U.S. Government. Did anyone else share your position?

A. Our judgment at that time was shared almost unanimously by the natural gas transmission industry (other than Northwest), Alaska gas producers, investment bankers, lending institutions, state and federal energy officials and regulators (except for the highest officials of the Energy Department), and concerned members of Congress.

13.Q. You seem to be clinging very carefully to the past tense in reporting your conclusions. Has anything happened since your last report to change your mind?

A. Yes, conditions have changed considerably. If we were writing the report today, we could not be nearly so categorical about the impossibility of private financing. We wrote in a couple of places that nothing short of Divine Intervention could make a wholly private financing possible. Well, the "Imam" Khomeini claims to speak with the voice of Allah, and he may in fact be the Saviour of the private financing plan. World oil prices have risen by almost 75 percent in the last year, and have practically banished any serious concern about the marketability of Alaska gas. At the same time, North Slope oil and gas producers and the state of Alaska are stuffed full of so much cash they hardly know what to do with it. They are certainly in a much better position than they were a year ago to give the pipeline financial support. Obstacles to private financing are still immense, however.

13.Q. What obstacles remain?

A. The Alaska Highway gas transportation system is a huge and complicated undertaking, with serious construction and operating risks. Its operating

risks include interruption or reductions in gas shipments caused by problems in the field, at the gas conditioning plant, or anywhere along the thousands of kilometres of pipeline, as well as a slight remaining possibility that the delivered gas will be priced so high that it cannot be marketed. More serious than these operating risks, however, are the risks of unforeseen engineering, regulatory, political, or legal problems that might prevent or indefinitely delay completion of one or more parts of the system.

Some of these risks are quite remote, but others are very serious, at least in the judgment of parties who will ultimately have to decide whether the pipeline can be privately financed. Big insurance companies, pension funds, and other large lending institutions, for example, will not take the risk of noncompletion or extended delay upon themselves.

15.Q. The Trans-Alaska oil pipeline (TAPS) was also an extremely risky project. It was delayed for many years and had stupendous cost overruns. Yet its sponsors were able to arrange debt financing for more than 90 percent of the pipeline's capital costs. Why do you consider the gas line to be different?

A. The oil companies that built TAPS used conventional "balance-sheet" financing. In other words, ARCO, Exxon, British Petroleum, and the Standard Oil Company (Sohio) put their entire world-wide assets behind the project debt. Even then, it is worth noting, one of the biggest insurance companies of North America declined to participate in Sohio's pipeline debt because it concluded that the risks were too great.

The financing plan for the Alaska Highway gas pipeline is quite different. The U.S. and Canadian sponsors of the gas line intend to use a technique called "non-recourse project financing". In contrast to the case of TAPS, the pipeline companies that are sponsoring the project would <u>not</u> be responsible for debt service if construction were delayed or abandoned, if the gas turned out to be unmarketable, or if gas shipments were reduced or interrupted. The only source of funds to pay interest or repay principal would be the ultimate consumers of Alaska gas in the United States.

Under present law, however, there is no way that Northwest Alaskan and the Foothills companies, or the American gas pipeline companies that would

ship their gas over the Alaska Highway system, can compel final consumers or even the local gas distributors to pay for gas they do not get.

16.Q. What are the legal obstacles to "tracking" all legitimate charges through to final consumers, and are these obstacles insurmountable?

A. The tracking problem applies to both operating risks and construction risks. The operating risks are a bit easier to deal with, so let's consider them first.

Suppose the entire transportation system has been completed and is in operation, but that an explosion and fire destroys the conditioning plant at Prudhoe Bay. The Northwest and Foothills tariffs provide that the gas shippers --- U.S. gas transmission companies --- must continue to pay a " minimum bill" to each of them that covers all debt service. The shippers are expected to sign service agreements --- contracts with Northwest and Foothills --- that oblige them to pay all charges authorized under the tariff. Yet there is nothing in the existing service agreements between the shipper pipelines and their own customers, the local gas distribution companies,

that oblige the latter to pay for transportation services on gas that is not delivered.

17.Q. Can't the service agreements be amended in order to cover the kind of contingency we have been discussing?

A. Yes, the contracts might conceivably be amended in this way. But at least some of the distribution companies and at least some of the state regulatory commissions are sure to resist such amendments.

18.Q. Doesn't the U.S. federal government have the right to override the states on matters that affect the interstate shipment of gas?

A. I'm not a lawyer, and I don't want to be too dogmatic about a sticky issue of constitutional law. But it <u>is</u> a sticky legal issue, and many experts doubt that the Federal Energy Regulatory Commission (FERC) currently has authority to enforce the perfect tracking of transportation changes on the Alaska Highway system in the face of opposition from a state utility commission.

It doesn't really matter how the Supreme Court would finally decide the question, however. Until the issue has in fact been decided --- and

litigation could take many years --- the big institutional lenders are not going to commit their money to a project whose only security consists of service agreements signed by Lower 48 pipeline companies which may --- or may not --- be able to collect from their own customers for all the charges imposed on them by the Northwest Alaskan or Foothills tariffs.

19.Q. So far you have discussed the tracking problem only with respect to operating risks. Is it any different in the case of delay or non-completion of pipeline construction?

A. The same principles that govern operating risks also apply to the risk of delay or non-completion, but the latter risk is a far bigger one. Moreover, the terms of the Presidential Decision selecting the Alcan route seem to preclude any contractual or regulatory resolution of the problem.

Suppose this time that the Northwest and Foothills pipeline segments are all complete and ready to operate, but that unforeseen engineering or legal problems prevent completion of the gas conditioning plant. Or assume that the conditioning plant gets completed, but that an explosion and

fire seriously damages it during the testing and shakedown period. How long would lenders to Northwest and Foothills be content with postponement of debt service, or with the risk --- however remote --- that the plant would never go into operation?

The tariff for each of the pipeline segments authorizes it to start billing its shippers as soon as that segment is completed, but the tariff will not be security enough for project lenders unless the lenders are confident that the minimum bill will be tracked "come hell or high water" to the ultimate consumers of gas. No such assurance exists today, and no such assurance is possible under present U.S. laws.

The President's 1977 Decision approving the Alaska Highway system makes it even more difficult to track pre-operational charges through to U.S. consumers: The Decision categorically forbids any "surcharges" on consumers prior to "commissioning" of the transportation system. Granted, the language of the Decision is ambiguous, and the parties are presently quibbling over the exact date on which the operators of each segment

of the transportion system will be allowed to start billing shippers. Nevertheless, the main thrust of the President's Decision is beyond dispute: American consumers as such will not be permitted to bear the risk that the pipeline will not be completed.

20.Q. Would you summarize your analysis with respect to the risk of non-completion or extended delay?

A. First, the institutional lenders absolutely will not assume the non-completion risk. Until that risk is securely and unambigously assumed by --- or imposed upon --- some other creditworthy party or group of parties, no section of the transportation system can be financed.

Second, under the Northwest and Foothills financing plans, the equity owners do not plan to assume this risk themselves. They are probably unable to do so in any case, at least with respect to the pipeline's debt capital.

Third, the existing service agreements between the U.S. pipeline companies and most of their local distribution companies do not oblige the latter to pay transportation charges on Alaska gas they do not get, or authorize them to pass such charges on to their customers. At least some of the some

state utility commissions will surely resist imposing such charges on the consumers whose interests they are legally and politically bound to defend.

To cap it off, the President and Congress have forbidden any tariff or financing scheme for the Alaska Highway system that imposes the risk of non-completion on gas consumers.

21.Q. What about the oil companies and Alaska? They have a tremendous stake in this project. Won't they ultimately be willing to assume most of the risks in order to get construction underway?

A. The three major North Slope gas producers and the State of Alaska are all on record as willing to participate somehow in financing the gas transportation system. Exxon has made a specific proposal with regard to producer investment in the system. The producers and the state are, in addition, now in an excellent cash position to participate. But the kind of support they can or will give is still very much in question.

22.Q. Your reports to the Alaska legislature implied that the state and at least one of the producers were not even capable of providing effective

financial backing. Have you changed your mind about this question?

A. About their ability to backstop the project, yes. The recent increases in world oil prices over the last year have dramatically improved the cash position of both the state and the oil companies, and there is now no question of their ability to give substantial support to pipeline financing.

23.Q. What is the problem then?

A. There are several problems. For one thing, the Presidential Decision prohibits the gas producers from having an equity interest or management voice in the transportation system.

24.Q. But can't the oil companies simply lend money to the Partnership, or guarantee pipeline debt?

A. Conceivably they can. But I am confident that they will not in fact lend money or guarantee debt --- at least without a voice in management. The sums are too large, the risks are too large, and the producers have serious doubts about the competence of the project's U.S. leadership.

Before any gas can be shipped on the Alaska Highway system, the gas producers must invest

another $1 to $2 billion in field development. FERC has, moreover, required the producers to absorb all gas conditioning costs, and by implication, the financial burden of building a $2 billion dollar gas conditioning plant. And finally, Alaska's Oil and Gas Conservation Commission is likely to direct the companies to institute waterflooding in the Prudhoe Bay reservoir at an additional cost of about $2 billion several years earlier than the companies would themselves have regarded it to be financial justified. So the producers' outlays other than for the pipeline will already cost on the order of $5 billion dollars, which will all be in vain if the entire pipeline system is not completed and put into operation.

Under these circumstances, the producers are not going to rush in with additional billions of dollars in unsecured credit, or with loan guarantees in behalf of other parties. Distinctions among equity, debt, and debt guarantees are almost meaningless so long as the main risk is non-completion or indefinite delay. Investors and guarantors will face the same absolute exposure: if the project is not completed in its entirety,

neither interest receives either a return of or a return to the funds placed at risk.

Exxon has proposed that the producers contribute 40 percent of the equity and 40 percent of the debt. Before the oil companies make any final commitment to the pipeline project, moreover, I am confident they will demand to see a final engineering design; like the institutional lenders, they will demand a clear legal resolution of the tracking problem; they will demand a reorganization of the Northwest Alaskan partnership with a major management voice for themselves, and they will demand something like equity rates of return to debt or debt guarantees until the whole system is assured of completion.

25.Q. Northwest and The U.S. Energy Department are both optimistic they can find some way to involve the oil companies without violating the Anti-Trust laws. Won't the Justice Department agree to anything the President really supports?

A. There is a general misconception about this issue. The Anti-Trust Division of the Justice Department categorically opposes producer ownership of oil and gas pipelines. The Justice Department has been publicly committed to this position for more than

forty years, but it has never tested it in the federal courts. The outcome of such a test is uncertain at best.

The problem is <u>not</u> the anti-trust laws or even the Justice Department's reading of the anti-trust laws. The problem is that President Carter accommodated the Anti-Trust Division's obsession on this issue in his Decision on the Alaska gas pipeline, by forbidding the gas producers any ownership role. When Congress ratified the President's Decision, the Decision became federal law, and this law cannot be repealed or amended without Congressional action.

The lawyers for the oil companies, Northwest, the Department of Energy, or even the Justice Department may be able to concoct a plausible legal theory permitting some kind of equity or management participation by the producers. One approach would be for the pipeline partnership to grant a contract for construction management to an entity controlled by the producers. But such a device may not be good enough; the oil companies are not the most popular people in America today. All it might take to block such a move would be for some Congressman, or some private citizen, to insist that the President's Decision is indeed the law, and that the

President meant what he wrote in 1977. I am not convinced that the oil companies can sneak into pipeline management simply by means of a legal ruse.

26.Q. What about Alaska?

A. Both the governor and the legislature have already committed themselves in principle to state financial participation. But it would be a mistake to assume that Alaska's interest in construction of the pipeline is so compelling that the state will do whatever may be necessary or, more accurately, whatever it is asked to do, in order to assure the project's success.

While elected officials and Alaskans generally tend to be in favor of the pipeline, it does not have the widespread and passionate backing that the TAPS oil pipeline and the unsuccessful "All-Alaska" gas transportation system received in earlier years.

Some Alaskans fear undesirable industrial development and population growth, while others hope that Prudhoe Bay gas can be kept in Alaska to fuel in-state industrialization. Another concern of is that cashing out of the state's gas reserves now will only intensify the hard landing expected

in the 1990's after Prudhoe Bay oil income has begun its sharp decline. And both the "right" and "left" ends of Alaska's political spectrum tend to be suspicious of government involvement in private industry. Finally, Northwest's public and political relations have been clumsy at best; the company's management is widely distrusted and disliked in Alaska. All in all, state financial support to the pipeline is not a terribly popular cause.

27.Q. What is required for Alaska to participate?

A. The Alaska government has essentially the same concerns as the oil companies --- completion of a final engineering design, resolution of the tracking issue, and existence of a credible financing plan and competent management. While Alaska can --- and in my judgment ought to --- make a large contribution to financing the project, the state is not likely to commit itself in advance of all the other parties, particularly the oil companies. Right now, Alaskans seem to be even more preoccupied with making natural gas liquids available for local petrochemicals manufacturing than they are with assuring that the pipeline can be built. State officials have made access to the liquids an absolute prerequisite to cooperation with the

project, but I am not sure what "access" really means and I am not sure that they do.

28.Q. What has to be done, therefore, before the pipeline can be financed?

A. Both the completion and operating risks have to be firmly and unambiguously allocated among parties that are both willing and able to bear them. We are very far from such an allocation of risks today. I see no way, moreover, that any workable allocation of risks can be arranged without some action by Congress.

29.Q. Do you still believe the U.S. government is the only party realistically capable of assuming those risks? Is there any way that federal loan guarantees could be avoided?

A. Under last year's circumstances, a purely private financing was almost inconceivable; as a practical matter, the outlook is still not terribly favorable. If the President and Congress had truly wanted to avoid government guarantees, the restrictions they put on private financing have been woefully shortsighted.

30.Q. You keep alluding to mistakes that the President and Congress made. Could you summarize these mistakes?

A. First, the President and Congress prohibited any penalties on prospective shippers of gas for non-participation in the project, and created no positive incentive for the former Arctic Gas companies to join the Alcan group. In 1977, twelve to eighteen companies were expected to join the Northwest Partnership, but as a result of federal shortsightedness, today there are only six. On the one hand, Section 13(a) of the Alaska Natural Gas Transportation Act (ANGTA) forbids the Partnership from making pipeline ownership a condition for shipping gas. On the other hand, the former Arctic Gas companies lost their entire investment in the rival project. In my view, FERC should have given these companies credit for all or a major part of their earlier investment, on the condition they joined the Alcan group.

The narrow equity base in the project has compelled its sponsors to seek totally non-recourse project financing, because they themselves don't have sufficient resources to back the pipeline's debt. There has never yet been a successful non-recourse financing of a major energy project in North America, and it is probably a hopeless strategy for such a big and risky venture.

The narrow equity base also means a narrow political base, incidentally, making it more difficult than it otherwise would have been to amend the Presidential Decision if it is necessary to do so in order to finance the pipeline.

Second, the President prohibited consumer surcharges in advance of the whole project's completion, knocking out the most essential condition for a successful non-recourse project financing, namely, the assurance that charges for debt service will be tracked to the final gas consumer whatever may happen, through an unbroken chain of tariffs and service agreements.

Finally, the President barred the only section of the energy industry that has sufficient assets or cash flow to back a major portion of project debt from participating in equity or management. This restriction on the gas producers' equity role makes it unlikely that the producers will provide much debt or debt backing.

Having undermined the possibility of private financing, the President's Decision also rejected the only reasonable alternative --- federal loan guarantees. The Carter Administration, moreover,

prevailed on the pipeline sponsors to promise Congress that they would never come back for such guarantees.

31.Q. What are the essential principles for a successful financing plan for the Alaska Highway Gas Pipeline.

A. Conceivably, there may be some combination of tariff provisions and regulatory measures that can satisfy lenders that all operating risks have been provided for. If the pipeline sponsors could convince lenders that no plausible combination of events could ever interrupt the flow of debt repayment and interest, it is remotely possible that a completed system could be privately financed with non-recourse borrowing. This arrangement, of course, means that the system's operating risks --- large or small --- have to be assumed by the consumers.

The risk of non-completion, however, is not going to be shifted to consumers. The gas producers and the State of Alaska, or the federal government or all of them, are somehow going to have to share this risk. But decisions on the allocation of benefits, costs and risks cannot be made piecemeal in a series of adversary proceedings before FERC, the NEB, and state regulatory commissions.

There is no way one can reasonably separate the treatment of field prices and the responsibility for gas conditioning costs; the share that the pipeline owners, gas producers, the Canadian government, or Alaska take in backing pipeline debt; the rate of return to pipeline equity; tariff conditions, including the risks shifted to gas distributors or final consumers; and the responsibilities assumed by the United States government. A major shift in any one of these parameters will change what some of the parties regard as fair and reasonable with respect to all of the others.

Someone has to coordinate or "broker" an overall financing plan that all the parties regard as workable and fair; and the negotiated plan has to be submitted as a package to the regulatory bodies and probably to Congress. My collaborators and I suggested the President designate someone like Robert Strauss or Felix Rohatyn to mediate the negotiations. While nobody of this stature has been appointed to play this role, the Energy Department finally seems to realize that the federal government must play a leading role in negotiating a financing package.

32.Q. Do you mean that all of the decisions taken so far may have to be reconsidered?

A. Not necessarily all of them. The general pipeline route, and the choice of sponsors in Canada and their organizational relationships do not need to be changed. I believe that all the parties can live with the existing wellhead price formula. One can argue that some of the technical decisions --- pipeline diameter and pressure, for example --- are not optimal, but these decisions are not central to the financing problem, and probably should not be reopened except for the most compelling reasons.

But the prohibitions on oil company equity participation and consumer surcharges; the "equal access" requirement, and the total writeoff of all pipeline company investments in the Arctic Gas project; the organization and leadership of the Northwest Alaskan partnership; the responsibility for conditioning costs; and the Alaska segment Incentive Rate of Return (IROR) have to be subject to reconsideration. And the possibility of federal financial aid must at least be open to consideration and negotiation.

Actually, except for federal financing, all of these issues are in fact being reconsidered right now in negotiations between the gas pipeline companies, the Department of Energy, and the producers.

33.Q. You mentioned the Incentive Rate of Return. FERC has supposedly made a final decision on the IROR for the Alaska segment. Could you explain why FERC's decision might have to be undone?

A. FERC's decision on the incentive rate rests on two legal fictions.

First, the commission ignored the difference between balance-sheet financing and non-recourse project-financing. Because the pipeline sponsors do not propose to guarantee project debt, their own financial exposure will be much less than it would be in a conventionally-financed venture. FERC awarded them a centre-point rate of return of 17.5 percent, on the basis of the return on equity in supposedly allowed "comparable" investments. But this is in fact a rate that would be appropriate to such investments only if they were financed on the sponsors' own balance sheets.

The upshot is that FERC has given the Northwest partnership a risk premium on its rate of return

that would normally be considered a reward for assuming the risk of guaranteeing project debt; this premium will now have to be paid twice --- once to the equity investors and once again to the parties that do actually guarantee the debt.

Second, the Commission believes that the Internal Revenue Code compels it to ignore the Investment Tax Credit (ITC) as a source of project equity, and indeed, to pretend that the ITC does not exist at all. What FERC now styles as a centre-point rate of return of 17.5 percent is in fact a return of about 30 percent.

There will be no pipeline unless some party or group of parties --- consumers, Alaska, the oil companies, or the federal government --- does assume the debt guarantee burden. Once someone other than the equity owners guarantees the debt, however, the risk to the latter fall dramatically; a 17.5 percent centre-point rate of return (and even more certainly, one of 30 percent) neither will be necessary to attract equity investment nor will it be politically tolerable.

Thus, the ultimate financing plan --- whether it is wholly private or involves government support ---

will create pressure on FERC to reconsider its ruling on the rate of return.

34.Q. To what extent does your financial analysis apply to Foothills? Are the risks the pipeline faces equally concentrated in Canada and the United States?

A. No, they are not. Foothills faces fewer hurdles in financing and constructing its sections of the pipeline. However, the Canadian sections of the Alaska Highway Pipeline cannot be financed and built unless the completion of the American portion is guaranteed, and unless lenders and equity investors in Canada are assured that no plausible combination of events in the United States could ever interrupt their revenues.

Thus, the most important financial risks arise in the United States, but their impact on the project's financing falls equally on the U.S. and Canadian segments. Completion guarantees or a resolution of the tracking problem for the American sections of the pipeline also serve to protect Canadian investors, but no part of the system can be built unless some party or combination of parties agrees to guarantee completion and debt service on all its components.

It is not clear at this time whether the Canadian segment of the pipeline will require separate and explicit guarantees from the U.S. or Canadian government, or from the gas producers. The answer will depend on the kind and amount of risk all other parties --- U.S. sponsors, gas producers, the dtate of Alaska and Canadian owners, and U.S. consumers --- are willing to accept, as well as the extent of backing the American government gives to the system's American portions.

35.Q. In your judgment, therefore, is it possible for you or I, or the National Energy Board, to assess the riskiness of equity investment in Foothills unless we know what the actual financing scheme will be for the U.S. portions of the pipeline?

A. No, It is not possible.

36.Q. And do we know today what that financing scheme will be?

A. No, we do not. I can say with reasonable confidence, however, that the actual financing will be different from any strategy Northwest, the U.S. Government or the gas producers have thus far publically proposed.

37.Q. Thank you, Dr. Tussing. Those are all of my questions at this time.

SCOMM

#14:15

HALLORAN
TUSSING-BARLOW
REPORTS

EVALUATING THE ALASKA HIGHWAY GAS PIPELINE PROJECT:

NATIONAL AND STATE BENEFITS, COMMERCIAL AND FINANCIAL VIABILITY, AND THE CONSEQUENCES OF DELAY

DRAFT

A PRELIMINARY REPORT TO THE ALASKA STATE LEGISLATURE

BY ARLON R. TUSSING

AND

CONNIE C. BARLOW

DRAFT

INSTITUTE OF SOCIAL AND ECONOMIC RESEARCH

UNIVERSITY OF ALASKA

ANCHORAGE AND FAIRBANKS

MARCH 1, 1979

AGO 559481

FOREWORD TO THE DISCUSSION DRAFT

This discussion draft is intended to become a part of the authors' third and final report to the legislature, expected in April. The final report will contain, in addition to these chapters, detailed technical notes describing the methodology and assumptions used in the calculations, and references for other factual and analytical statements in the text.

Comments on this discussion draft may be forewarded to me at the address below, or directly to the authors.

GREGG K. ERICKSON
Director of Research and Analysis
Legislative Affairs Agency
Pouch Y
Juneau, AK 99811

March 7, 1979

AGO 559482

INTRODUCTION

The proposed Alaska Highway gas pipeline confronts Alaska and the United States with the same dilemma: the project seems to offer substantial net benefits to each, but a favorable benefit-cost ratio is not the same thing as a viable enterprise, and not every prospectively viable enterprise can be financed in private capital markets. As a result, the expected state and national benefits may be lost or postponed unless one or both governments accept financial burdens or take other actions that are not normally regarded as governmental responsibilities in the United States.

In 1978, the State of Alaska received an explicit request --- which has this year taken on the tone of an ultimatum --- that it participate directly in pipeline financing. While the project sponsors have not yet approached the federal government with a similar demand, it too must be prepared to respond.

Prudent decisions about state or federal financial participation must be grounded on a comfortable understanding of at least two basic questions:

(1) From either a state or federal standpoint, what are the benefits of this project; and

(2) How crucial is governmental support to the

project's success?

The following chapters provide an overview of the benefits the state and nation might expect to receive. Likewise, they review the commercial and financial prospects of the pipeline venture. The dimension of time is added, with a look at how delays might affect both the benefits and the project's viability. Two closely related issues are postponed for other chapters of the final report: (1) Is debt or equity investment in the pipeline a prudent risk for the state, and (2) How far might other parties (the sponsors, producers, and lenders) be willing to go in taking on financial risks.

AGO 559484

CHAPTER I

NATIONAL AND STATE BENEFITS

It is a widespread belief that the "cost" of gas delivered through the Alaska Highway gas pipeline will be five or six dollars or more per thousand cubic feet (mcf). Such a statement makes the project look like an extravagant boondoggle in view of the fact that the U. S. Department of Energy last summer rejected as overpriced an opportunity to buy similar quantities of Mexican gas at $2.65. If comparative costs were really so disadvantageous to the Alaska project, its construction would clearly be against the national interest, and its commercial prospects would be nil. Further consideration of state support to the project would be a preposterous waste of time.

Five to six dollars is not an unrealistic estimate for the price of Alaska gas in Lower 48 markets, but it is important to understand what this estimate means, and what it does not mean. Firstly, the correct measure of the cost of Alaska gas to the United States is not its final price to consumers, but its "real resource cost" --- the value of the labor, capital and materials actually consumed in producing, conditioning and transporting the gas. The consumer price includes important charges that are not real resource costs

to the nation but only "transfers" from U. S. consumers to gas producers or governments.

Secondly, the $5 to $6 figure is in inflated dollars several years in the future. In 1983, 1984 or 1985, when the pipeline finally goes on stream, the prices of alternate fuels, including imported gas from Mexico, will be much higher than they are now (though how much higher is a critical issue for the pipeline's financial viability).

Finally, the initial price of Alaska gas delivered through the pipeline is not necessarily representative of the price that will prevail over the facility's entire economic life. Pipeline tariffs, like most utility rates, are calculated against a "rate base" that declines as the original investment is amortized, while larger gas shipments after the first years may reduce the amount of the fixed capital charge that each mcf of gas must bear. It is possible (though not inevitable), therefore, that the price of Alaska gas would go down over the years.

Thus, the price of Alaska gas in inflated dollars during the early years of pipeline operation is certainly a relevant consideration in judging the marketability of the gas and the project's commercial outlook. But it is not a meaningful measure against which to weigh the project's national benefits, nor an effective index of its long-term

viability.

There is no single, correct method for judging either net benefit to the nation or the business prospects of the pipeline venture. The following pages do, however, try to put the two concepts into perspective. The details of our assumptions and procedures may reasonably be debated, but we are confident of the major thrust of their results: the Alaska Highway gas pipeline almost certainly offers substantial net economic benefits to both the United States and the State of Alaska, but its soundness as a business venture is marginal at best without extraordinary kinds of government assistance.

NATIONAL BENEFITS

The national case for the Alaska Highway pipeline is a strong one. It consists of the following generally valid arguments:

1. Measurable and predictable economic benefits. The measurable and predictable economic benefits of the project for the United States (and for Canada) are strongly positive. Even with large cost overruns and stable real prices for imported oil, the value of Alaska natural gas delivered in the Lower 48 states

AGO 559487

would almost certainly exceed its real resource cost --- the value of labor, materials, and capital inputs. Even with a total capital cost of $17 billion 1979 dollars for field development, conditioning and pipeline facilities, and a gas volume of only 2.0 billion cubic feet per day (bcf/d), the average resource cost of Alaska natural gas delivered through the Alaska Highway system is not likely to exceed $2.40 per thousand cubic feet (mcf) in 1979 dollars over a 20 year economic life, while the average 1979 cost of an equivalent volume of imported low sulfur residual oil (No. 6 fuel oil) will probably be more than $2.80. These figures imply a minimum economic benefit to the nation of about $440 million per year in 1979 constant dollars.

2. Measurable but speculative economic benefits. The total benefits of the project would be even greater in the likely case that it carried more gas than the 2.0 bcf/d minimum projected from Prudhoe Bay over the first 20 years of operation. The existence or anticipation of a gas transportation system may in fact be a powerful stimulus to petroleum exploration in the Arctic, and thus on the amount of additional gas discovered. Increasing the flow to 3.0 bcf/d and the

economic life to 30 years would reduce the maximum cost of Alaska gas to about $2.25 per mcf in 1979 dollars, for a minimum national economic benefit of about $550 million per year.

3. National security and international payments. Natural gas produced in the United States (or in Canada) will displace imported oil that is less secure and has a high foreign exchange cost. To the extent that Arctic gas supplies reduce world oil demand, they will also help to restrain future OPEC price increases. Alaska gas promises to supply about three quarters to one tcf of gas each year to U. S. markets, which now receive about 20 tcf per year.

4. Environmental considerations. Environmental, safety, and social disruption problems from the Alaska Highway project are probably lower than from any other currently available source of similar amounts of energy. (Consider, for example, coal mining and conversion, nuclear power, and offshore drilling.)

5. Alternatives. Hypothetical alternatives exist to the proposed pipeline for moving or using Prudhoe Bay natural gas, including transportation as methanol or by LNG icebreakers, and local petrochemical manufacturing. None, however, appears to be tech-

nically and economically feasible in the near future, at least for the volumes of gas available at Prudhoe Bay.

ALASKA BENEFITS

There is also an impressive case for the pipeline from an Alaskan viewpoint; the state clearly stands to be the biggest single beneficiary from production of Prudhoe Bay gas. The main elements of the Alaska economic case are the following:

1. Measurable and predictable revenue benefits. For each mcf of gas produced, the State of Alaska could expect to receive about 35.5 cents in 1979 dollars in royalties and production taxes if Prudhoe Bay gas sold at its legal ceiling price ($1.45 in March 1977 dollars --- about $1.75 in 1979). The state also levies a 20 mill tax on oil and gas pipeline property, and a 9.4 percent corporate income tax. With marketed gas production of 2.0 bcf/d, the state's total revenues from these sources would be on the order of $340 million per year in 1979 dollars. Increases in the need for state services directly due to the pipeline or gas sales would be minor in comparison.

AGO 559490

2. Measurable but speculative revenue benefits. Any additional gas carried by the pipeline beyond the 2.0 bcf/d minimum projected for the Prudhoe Bay field would increase net state revenues almost proportionally. 3.0 bcf/d would produce expected state revenues of about $460 million per year, with very little offsetting increase in the demand for state services. To the extent that the existence of a transportation system for Arctic gas would stimulate industry interest in exploration, state oil and gas leasing bonuses and rentals might increase significantly.

3. Direct employment effects. Field development and construction of the pipeline and conditioning plant would require 50-60,000 man years of direct labor in Alaska over a four-year period. There would be several hundred permanent jobs in administration, operation and maintenance of the field, plant and pipeline.

4. Multiplier and induced economic effects. The spending of construction payrolls and state revenues will reverberate throughout the Alaska economy, creating further jobs, additional state revenues, and further increases in gross state product and personal income. Increased income and employment opportunities will encourage net in-migration to Alaska, further swelling

AGO 559491

the labor force and population. Values will rise for assets such as urban land and housing whose supply is fixed or relatively inelastic, thus increasing the real wealth of some present Alaska residents.

5. Energy for Alaska households and industry. A transportation system for moving Alaska gas to the Lower 48 may also make natural gas (and perhaps natural gas liquids) available for residential, commercial, industrial and electric utility use in Fairbanks and elsewhere in interior Alaska.

6. Environmental considerations. Expected and potential environmental, safety and social disruption problems from the project are probably lower than for any other foreseeable source of comparable state revenue or personal income. (Consider, for example, coal or metallic mining, timber, or even tourism.)

7. Alternatives. Exactly the same point can be made about other uses of Prudhoe Bay gas for the state as for the nation: plausible alternatives do exist, but none of them seems economically feasible in the foreseeable future.

Not all the foregoing effects on Alaska's economy are wholly predictable, nor are they necessarily unmixed blessings.

The net revenues from gas sales almost certainly will not be as great as the state now anticipates because the price for Alaska gas established by the Natural Gas Policy Act of 1978 is only a ceiling above which the outcome of private sales negotiations and regulatory interference may not penetrate.

Pipeline construction would repeat the inflation and social turmoil of the TAPS oil line boom, albeit on a somewhat smaller scale, while construction jobs will not necessarily mitigate Alaska unemployment in the long run, and may indeed worsen it. The permanent increase in labor force and population, moreover, would have a mixed (and controversial) effect on the Alaska environment, and the style and quality of life in the state. Not every Alaskan agrees that increased leasing, exploration and development in the Arctic is desirable at this time. Finally, some Alaskans do not regard industrial development based on natural gas or gas liquids as necessarily a good thing, while others would be willing to give up or postpone the predictable revenue benefits from the Alaska Highway project in the hope that an alternative system more favorable toward Alaska processing operations will eventually turn up.

Notwithstanding all these reservations, there is one outstanding feature that the indirect, speculative, or

debatable Alaska "benefits" of the pipeline project (other than the construction boom) have in common: state government can control or at least influence them powerfully through mineral leasing, taxation and environmental policy, or by controlling the amount and kind of government spending. The measurable and predictable revenue benefits may be spent currently, used deliberately and consciously to stimulate further economic growth (perhaps as subsidies to industries as diverse as bottomfishing and chemical manufacturing), or invested outside of Alaska to meet future budget needs. At least according to conventional ways of thinking, therefore, there is little question that the prospective leasing and tax revenues would be real benefits to Alaska's economy, which the state may spend currently or invest for future needs at its own discretion.

CHAPTER II

ECONOMIC VIABILITY AND FINANCIBILITY

MARKETABILITY AND ECONOMIC VIABILITY

The fact that the real economic (or resource) costs of Alaska natural gas over the life of the pipeline will almost certainly be less than the cost of substitute fuel (No. 6 oil) does not necessarily imply that the consumer cost of Alaska gas will be less than the consumer cost of the alternative. And because the viability of the project depends upon the willingness of consumers to pay for the gas, the existence of net economic benefits does not automatically mean that the pipeline is a sound business venture.

The economic cost of producing, conditioning and transporting Alaska gas to the Lower 48 is composed only of amortization and return on the labor and materials invested in field development, pipeline and conditioning plant construction, plus the relatively small cost of labor and materials required for administration, operation and maintenance. The consumer cost of gas includes very substantial additional charges, the most important of which are the excess of the field price over the real resource cost of gas production and conditioning, plus Alaska and Canadian taxes.

There are other minor additions and some offsets (like the investment tax credit) which combine to make delivered cost of Alaska gas to U. S. consumers substantially different from its resource or economic cost.

Up to this point, moreover, the costs and benefits of the pipeline project have been discussed in terms of "levelized" values in inflation-adjusted dollars. In the real world, however, the marketability of Alaska gas and thus the viability of the pipeline project will depend upon the structure and the time profile of transportation and distribution charges (which will not be levelized). It also rests upon the ability of Alaska gas to meet the prices for alternative fuels in current nominal dollars, a consideration profoundly affected by the rate of future inflation. The following pages consider the effects of field prices, taxes, utility rate design, and inflation on the soundness of the Alaska Highway project as a business venture in which consumer charges must meet all its costs.

1. Field or "wellhead" prices. The gas producers and the State of Alaska both expect, and are legally entitled to demand, $1.45 in March 1977 dollars (about $1.75 in 1979) for each mcf of Prudhoe Bay gas. While the producers may eventually agree to a field

price lower than this ceiling established in the Natural Gas Policy Act of 1978, they will nevertheless insist on some payment beyond the bare "incremental cost" of field development, on the ground that the gas ought to compensate them for its "fair" share of the joint costs of leasing, exploring and developing the field for both oil and gas, plus a reasonable profit.

Assuming that the producers and the State are able to negotiate contracts at the ceiling price, but that they have to absorb production and conditioning costs of about 73 cents per mcf, the field price would add about $1.02 per mcf to the average consumer cost of the gas, beyond that determined by the actual input of labor, capital and materials. Consumers would have to pay the field price plus the production tax on gas used as pipeline fuel, as well as on delivered gas. At a 94 percent net fuel efficiency for the pipeline, this charge would be about 12 cents per mcf.

2. State, local and Canadian taxes. Federal taxes on corporate income are legitimately regarded as part of the resource cost of producing and delivering the gas, because the capital used in the project has to earn a high enough pre-tax return to bid it away from other potential investments where its profits would also

be subject to the corporate income tax. But state production, sales, and corporate income taxes, Canadian taxes, and import tariffs are additions to the costs of labor, capital and materials. Thus, at a field price of $1.75, the state production tax adds 16 cents per mcf to consumer costs; with net gas deliveries of 2.0 bcf/d, Alaska and local property taxes would add about 8 cents, state income taxes 3 cents, and Canadian federal and provincial taxes about 18 cents.

Other possible differences between the economic or resource cost of Alaska gas and its delivered cost to consumers include the investment tax credit, which reduces fixed costs by about 12 cents per mcf; the "excess" profits, if any, allowed the pipeline owners above the minimum return required to attract equity; Lower 48 state and local taxes (on the Northern Border and Western leg systems); and charges for gas transportation and distribution beyond the "tailgate" of the Alaska Highway system.

Ignoring some of the smaller or more speculative items, we can arrive at an order of magnitude estimate of the price of 2.0 bcf/d of Alaska gas delivered to Lower 48 consumers, "levelized" in 1979 dollars. The major elements above total $3.82:

AGO 559498

Consumer cost of Alaska gas in constant 1979 dollars

Field Price	$1.75
Production Tax	.16
Other Alaska Taxes	.11
Pipeline Fixed Cost	1.42
Pipeline Fuel	.12
Operation and Maintenance	.20
Canadian Taxes	.18
(Less) Investment Tax Credit	(.12)
TOTAL	$3.82 per mcf

It should be remembered that this list is not complete; in particular, it includes no transportation and distribution costs beyond the tailgate of the Alaska Highway system. It does assume that the producers receive the statutory ceiling price for gas in the field, but that they must absorb gas conditioning costs as a preliminary FERC ruling. This decision is being disputed; if gas purchasers had to pay all conditioning charges, the consumer cost of gas would rise about 40 cents more.

Thus, with the same relatively high capital cost assumptions used in the last section, and with net deliveries of 2.0 bcf per day, Alaska gas would not be a commercially sound venture today: consumers with a choice of fuels would not buy Alaska gas at its full cost. The viability of the pipeline project therefore depends upon (1) a firm conviction that both the nominal and real prices of

AGO 559499

substitute fuels will increase very substantially, or (2) a firm conviction that consumer subsidies in the form of rolled-in and "value of service" pricing, and "front-end loaded" tariff profiles, could bridge any foreseeable gap that may occur between the delivered cost of Alaska gas and its market value.

These regulatory issues were elaborated in an earlier report in the present series, and will be treated again elsewhere in the final report. It is sufficient here to point out four important reasons why the two preconditions above may not be satisfied.

First, while it is a reasonable assumption that world oil prices will continue to rise, there are some very plausible circumstances in which they might remain stable or even fall in real terms for a number of years, at least after the end of the current Iranian crisis.

Second, the ability of rolled-in pricing to subsidize high-priced supplemental gas depends wholly on the "cushion" of low-price gas flowing under old contracts; this cushion will be largely depleted by the late 1980's.

Third, Congress and the President, through the Alaska Natural Gas Transportation Act and the decision selecting the Alaska Highway system, have explicitly rejected some of

AGO 559500

the rate design mechanisms FERC might otherwise have employed and which may yet be essential to assure the marketability of Alaska gas.

Finally, it is not sufficient to deal with gas marketability in general, as we have done here. Specific gas transmission companies must want to acquire the gas, and be confident that they can track all of its costs through their distribution company customers to final consumers. Each system's willingness and ability to move the gas must be judged on the basis of its own customer mix; the size, term, and cost of its existing gas supply; and the policies of state regulatory commissions in its market area. As far as the authors can ascertain, neither FERC nor the pipeline sponsor has conducted this kind of demand analysis --- without it, even the most optimistic assumptions about gas marketability in general do not assure the commercial viability of the proposed project.

IS COMMERCIAL VIABILITY ENOUGH?

The previous pages have shown that a project that can be justified on the basis of predictable national economic benefits may not be a sound commercial venture. The same assumptions that generated an <u>average cost to the nation</u> of

about $2.40 per mcf for Alaska natural gas, suggested that its average cost to consumers would be about $3.82, both in terms of constant 1979 dollars. The one is considerably less, and the other considerably more, than the 1979 cost of substitute fuel. The Alaska Highway pipeline project seems, therefore, to be a worthwhile project from a national standpoint, but a questionable one from the standpoint of consumers or private investors.

Just as the promise of national economic benefits does not guarantee commercial viability, so the promise of a profitable venture does not necessarily mean the project can be financed (unassisted) in private capital markets. A venture whose success rests on large future price increases, however likely they may now seem, and on future actions by regulatory bodies, no matter how reasonable they appear today, bears a heavy load of "ordinary" commercial risk. The Alaska Highway project is also subject to some "extraordinary" engineering, political and regulatory risks, which will be considered further in another part of the final report.

Thus, two interacting characteristics of the proposed project make its financial viability doubtful. One is the range and severity of risks, and the other is the tremendous scale of the project. Either characteristic alone might not be terribly troublesome. For example, if the risks remained

unchanged but the capital commitment required of each lender or sponsor were not nearly so huge, cash might be forthcoming: Each party could afford to make a bad judgment without jeopardizing its overall well-being. Recognizing this, the gas pipeline's sponsors intend to seek debt contributions from as many different sources as possible, and the Department of Energy hopes that virtually all of the major gas transmission companies will take an equity position.

Likewise, if the project size remained unchanged but its risks were substantially reduced, financing would also be less of a problem. This principle has motivated the sponsors of the Alaska Highway group to design a system whose technological, engineering and political risks were considerably less than those of their former rivals, El Paso, Alaska and Arctic Gas.

A previous report in this series elaborated on the reasons that risk-reduction is still insufficient to attract sufficient private debt and equity to this project. Elsewhere in the final report, we shall set out in detail the preconditions for allocating ordinary and extraordinary risks in such a way that the pipeline might be financed.

CHAPTER III

THE CONSEQUENCES OF DELAY

INTRODUCTION

Whatever state or national perceptions may be of the costs and benefits of this proposed pipeline, or of its commercial or financing outlook, the likely consequences of project abandonment or serious delay are crucial considerations in deciding how much of the financial burdens and risks either government could responsibly assume. If the project is not put together now, what does the state or nation lose (or gain) in the meantime? What are the chances that it (or something functionally similar) might be put together later --- and under more or less favorable conditions?

If one believes that failure to finance and build the pipeline immediately would be a disaster to the state or to the nation, prudence demands that government be prepared to step out front on financing matters. On the other hand, if the consequences of delay are not judged so ominous, then a more restrained approach may be in order.

The consequences of delay should be looked at in two ways. First, what is the effect of a simple postponement of benefits? Second, how might a delay alter the actual

AGO 559504

character or scale of the expected benefits, or the project's viability?

THE EFFECT OF DELAY AS A POSTPONEMENT OF CERTAIN BENEFITS

Preceding any speculation of how conditions might change in the event the pipeline is delayed (and whether such changes constitute net benefits or net costs), one must examine the effect of a delay all else being equal. That is, if the costs and benefits were to remain the same whether the pipeline is built now or later, what difference would a delay in and of itself mean to the State or nation?

Notwithstanding Department of Energy statements extolling the long-term benefits of Alaska gas to U. S. consumers, the unique national benefit of Alaska gas is usually perceived as its contribution to increased domestic energy security and as an offset to the increasing flow of U. S. dollars to foreign (particularly OPEC) nations. One might argue against building the pipeline now on the theory that world energy supplies will keep getting tighter. The indicated U. S. policy, therefore, would be to "drain Arabia first," keeping Alaska oil and gas in the ground until it is desperately "needed." In truth, no one knows whether energy security and international payments problems will be more

pressing in the mid-1980's, when the pipeline is scheduled to go on stream, or some twenty years later, when the Prudhoe Bay field would have been largely depleted under the present production schedule.

The current Iranian crisis demonstrates, however, that the security and price of imported oil are real problems today, and they will almost certainly still be problems five years from now. Further, it is very likely that the Alaska gas transportation system will in fact carry significantly more gas than has yet been proved up in Arctic Alaska, and for considerably longer than 20 years. Viewing the pipeline as opening up a potential energy frontier that could supply the nation with secure domestic energy for thirty, fifty or more years, there is little point in "saving" Alaska gas for a more acute future crisis that may never materialize. All other things being equal, the national strategic benefits of the Alaska Highway system argue for building it sooner rather than later.

The primary benefits to the State from the proposed project are usually cited as jobs and money. The question of jobs now versus jobs later, like the question of how soon the nation increases its security of domestic energy supplies, does not lend itself to rigorous mathematical analysis. One observation is in order, however: Whenever it may take

place, pipeline construction is too far away in time to be a meaningful cure for Alaska's present post-TAPS slump. Before any pipeline jobs come along, most of the currently unemployed will have had to find other jobs, leave Alaska or starve.

On the other hand, much technical debate has already taken place in Alaska about the "time value" of money to the State. All else being equal, what difference does it make whether the State earns a billion (inflation-adjusted) dollars in royalties over a twenty year period beginning in 1984 or beginning in 1990?

Simply stated the "time value" of money reflects the fact that a dollar today is worth more than a dollar tomorrow because (1) we can invest today's dollar in such a way that we will have more than a dollar tomorrow, and (2) we would have to repay more than one of tomorrow's dollars in return for borrowing a dollar today. This concept sounds rather simple on the surface --- so we will leave it at that. When employed to determine the consequences of a delay in the receipt of revenues, however, it is actually quite complex, and, like most tools of economic analysis, is only as good as the assumptions with which it is combined. The most difficult (and important) assumption turns on the question of what is the proper "discount rate" for dollars

AGO 559507

accruing to a particular entity --- in this case, the State.

Moreover, whatever one concludes with respect to the "time value" of money for the State and the consequent "costs" of a delay in gas royalties and taxes, one ought to remember that several qualitative factors may be as important as the "discounted present value" of state revenues. If state officials attach some special value to early receipt of cash -- say a need to meet ongoing government operations, cover debt service obligations, or fund capital improvements for which borrowing is not an acceptable alternative because of constitutional restrictions, political pragmatism, or plain business sense -- then a strict profit-maximizing calculation of the time value of gas revenues is not the appropriate basis upon which to make decisions. Likewise, those who believe that having spare cash on hand to reinvest within Alaska carries some intangible benefits will probably attribute a higher value to early generation of cash than might be accorded by a traditional "time value" formula.

On the other hand, if one views the goal of "saving" the State's nonrenewable resource wealth for future generations as worthwhile yet difficult to achieve, then again the conclusions drawn from time value analyses would be viewed with skepticism. In this case, even if conventional financial analyses showed convincingly that the State would be better

AGO 559508

served by cashing out its resource wealth earlier rather than later, and investing it in assets that yielded a higher rate of return than gas in the ground, one may nevertheless wish to postpone the metamorphosis of hydrocarbons into cash. Such an approach may be the only certain way to avoid swelling the bureaucracy, underwriting risky developmental ventures, or otherwise spending what should really be saved.

THE EFFECT OF DELAY ON THE CHARACTER AND SCALE OF EXPECTED BENEFITS AND THE PROJECT'S VIABILITY

Up to this point, our discussion of the consequences of postponing pipeline construction has assumed that its benefits remain essentially the same in kind and magnitude regardless of their timing. If this premise is accepted, economic and strategic benefits to the nation seem to argue strongly for early construction and gas sales. Alaska's fiscal interests may tilt the argument in the same direction, with the important reservation that the State might not have the ability to carry out a financial strategy that maximizes the present worth of all its future revenues --- even if it wanted to do so.

In the real world, postponement of benefits from

producing Prudhoe Bay gas will involve important changes in the scale and character of those benefits and the project's viability. It will surely have some impact, for example, upon:

(1) the volume of gas available for sale;

(2) the costs of producing, processing, and transporting the gas;

(3) the demand for the resource and its consequent "market value."

The following pages will explore what these changes might be, and how such changes might affect the project's viability and the benefits to Alaska and the nation.

THE EFFECT OF DELAY ON THE VOLUME OF GAS AND OIL AVAILABLE FOR SALE

An understanding of what is likely to happen physically to hydrocarbon resources at Prudhoe Bay if pipeline construction is postponed is probably one of the most important considerations from either a State or national viewpoint. The authors' non-expert understanding, both from the published literature and from conversations with experts, is that prolonged gas reinjection would create no foreseeable danger to oil recovery, that the physical loss of gas would be minor (at least in comparison to the financial cost of

AGO 559510

postponing gas sales), and that the capital outlay for necessary reinjection facilities would be essentially the same whether or not the proposed gasline is built according to present schedules.

Our impression of a consensus among the experts is not shared, however, by responsible officials of all the affected companies. The various parties with whom the authors have discussed this question seemed reasonably certain that they knew what the consequences of prolonged gas reinjection would be, but surprisingly, their opinions were far from unanimous. For example, a spokesman for one of the Prudhoe Bay gas producers maintained that loss of gas volumes resulting from prolonged reinjection would be minimal --- and he, in fact, stressed the value of prolonged reinjection for increasing ultimate recovery of the associated oil resource. Spokesmen for another producer, however, painted a gloomy picture, warning of substantial gas loss in the event gas pipeline construction is seriously postponed; while a major institutional lender felt certain that gas offtake and sale by 1981-82 were absolutely essential for proper field management of oil as well as gas.

A related question involving more visible public controversy is the effect of early gas production on the ultimate recovery of oil from the Prudhoe Bay field. Most engineers seem to agree that gas production will entail some

sacrifice in oil recovery, or at the very least, will require greater investment in water injection to avoid the potential loss of oil. A few engineers have argued that prudent operation of the reservoir requires reinjecting all of the gas produced in association with crude oil, postponing gas sales until after the oil has all (or nearly all) been produced. Making a rational decision on this issue, however, requires a judgment on the relative value of oil and gas at different times in the future, and on the appropriate discount rate for weighing earlier against later revenues, as well as a knowledge of reservoir engineering.

The State has contracted for a detailed study of the likely costs and physical effects -- translated into economic consequences -- of various gas production profiles for the Prudhoe Bay field, including prolonged gas reinjection. There is some chance that this and other subsequent studies would indicate that prudent reservoir management (with due consideration of financial factors) would dictate postponing gas shipments beyond 1983-84, or limiting them to volumes less than the economic threshold of pipeline viability --- but we would not rate these chances as very high.

In addition to a technical evaluation of the effects of prolonged gas reinjection on the functioning of the Prudhoe Bay reservoir, one should consider several other issues

which likewise affect the volume of gas available for sale and, thereby, the project's viability.

First, regardless of the actual effect of delay on the volume of oil and gas ultimately recoverable, delay will certainly increase the confidence in the predictions voiced by reservoir engineers, corresponding to an accumulation of field production history upon which predictions are based. To date, a lack of production history and the attendant uncertainty about reservoir performance has been one element impairing gasline financing, which depends upon a reliable flow of gas at projected volumes.

Second, delay may also provide a better understanding of how much gas might exist in other known reservoirs on the Arctic Slope (such as the Kuparuk and Cape Thomson) and how much gas might be discovered elsewhere in the region, for example, in the National Petroleum Reserve or the Beaufort Sea. Here too, added certainty of supplies -- and particularly any increases in proven reserves -- will improve the financing prospects for a transportation system, and will additionally assist in the design of its optimal capacity.

Third, the presently acknowledged delay in pipeline startup from 1982 to 1983-84 or later has already boosted the expected initial volumes of gas shipments, thereby reducing the proportion of fixed transportation costs each

unit of gas must carry. This conclusion is based on a virtually uncontroversial axiom of reservoir engineering --- that is, the notion that the daily volume of gas removal consistent with prudent reservoir management increases as oil is produced.

THE EFFECT OF DELAY ON THE COSTS OF PRODUCING, PROCESSING, AND TRANSPORTING PRUDHOE BAY GAS

One commonly cited economic effect of delaying the pipeline project is the belief that for each year construction is postponed, the system's capital cost will inflate by hundreds of millions of dollars. While this is not a particularly controversial statement, the extrapolation that such a consequence is necessarily "bad" has no justification. It is a valueless statement unless viewed in the context of assumptions about how the market value of gas likewise changes through time, and what the "discount rate" or "cost of capital" is held to be.

For example, if the real (i.e. inflation-adjusted) prices of construction and the market value of gas remain the same -- in other words, if construction costs and gas prices rise at the same annual rate as general inflation -- the real profitability of the pipeline (and the net national benefits from it as well) will be essentially the same

regardless of when it may be built. In this case, the "time value" principle probably argues for early construction. Complications arise, however, if construction costs and the value of gas are not expected to increase in tandem. The importance of those complications is magnified if the current prices of gas do not justify the project, but future price increases are expected to do so. In this instance, the timing of construction may make a big difference: Should the facility be built now, ahead of effective demand, in order to evade higher future construction costs, or should it be postponed until market conditions are more favorable despite rising capital costs?

The correct answer depends mainly upon the interplay of three factors: (a) the rate at which construction costs are expected to inflate, (b) the rate at which the value of the gas is expected to increase, and (c) the time value of money, as represented by the "cost" of capital (the rate of return the funds invested in the pipeline could earn in other uses.) It is a principle of natural resources financing that development ahead of demand is warranted only where (a) capital costs are expected to increase at a rate that is higher than the sum of (b) the rate at which sales prices (e.g. delivered prices for natural gas) are expected to increase and (c) the necessary return to capital.

Such a circumstance is certainly conceivable, but it does not seem very likely with respect to the present proposal. Consider some illustrative numbers: Suppose the value of gas is expected to increase at about 8 percent per year, while the rate of return on pipeline investment is 15 percent. Do we really expect construction costs to rise at a rate of 23 percent annually? Conceivably, but not very likely!

Thus, we can conclude that it probably makes more sense to build the pipeline earlier than later, but only if it is otherwise worth building at this time. Anticipated construction cost escalation is a legitimate consideration in timing the project, but it would not be a sufficient reason to build the pipeline before it could meet either a net national benefit or a marketability test.

In addition to the cost effects of delay posed by construction cost fluctuations and market value changes that do not move in tandem through time, one must consider the likelihood of technological or other breakthroughs which may sweeten project economics at some future date. Such a breakthrough might be of the sort which simply decreases the costs of constructing the project as now proposed. It might, instead, prompt a change in routing or design --- for instance to take advantage of economies of scale presented

by prospects for a gas transportation system that would serve the entire Canadian Arctic, as well as Northern Alaska. Or a substantial change in the project scope may take place: ice-breaking tankers, or in-state processing of gas into methanol, fertilizers or petrochemicals may prove more attractive. Underlying all speculation, of course, is the oft-cited "fallback" alternative of simply running the gas through an empty TAPS oil line 25 years from now.

Prudence, nevertheless, dictates that one not place unwarranted optimism in the prospects for speculative breakthroughs. The hope for any one of them must be weighed against the much greater likelihood of success for a conventional project already under way. Any alternative that involves delay, moreover, must be promising indeed to overcome the general presumption in favor of an early start that comes from the conventional discounting of future benefits.

THE EFFECT OF DELAY ON THE DEMAND FOR PRUDHOE BAY GAS

Spokesmen for the pipeline sponsors have argued that Prudhoe Bay gas must be sold quickly in order to tie up markets before potentially cheaper (at least in the short-term) supplies of Canadian and Mexican gas flood the U. S.

AGO 559517

market. Interestingly enough, this scenario has very little to so with the real market demand for Alaska gas; it hinges more on institutional motivations and perceptions of the need for Alaska gas.

Supplemental gas supplies -- be they Canadian, Mexican, Alaskan, Algerian, or whatever -- are not ultimately destined for use in so-called "premium" gas markets where residential and small commercial customers view electricity or distillate fuel oil (No. 2) as the alternative to gas. Existing Lower 48 reserves of conventional gas could satisfy these markets well into the next century. Instead, the main effect of supplemental supplies will be to allow the United States to continue burning gas in "low priority" markets, where residual fuel oil (No. 6) and coal are the alternate fuels. Given reasonable time for fuel users to adapt to the fact of more abundant gas supplies, this low priority market (encompassing the use of gas, oil or coal as industrial and electric utility boiler fuel) is virtually unlimited --- at least within the range of plausible gas volumes.

Hence, Canadian, Mexican and Alaskan gas are not competitive with one another, so long as they are all competitive in price with residual oil. The only way in which the entry of substantial volumes of Canadian and Mexican gas would adversely affect the marketing of Alaskan

AGO 559518

gas is if the supplies are purchased at prices that remain significantly above that of No. 6 oil --- in which case, the "cushion" of cheap domestic gas under old contracts will be used to offset the higher-than-market price. If the marketability of Alaskan gas in the early years of pipeline operations explicitly depends on this cushioning effect, relatively high-cost Mexican or Canadian gas will compete with Alaska gas for the implicit subsidy provided by rolled-in pricing. This principle is not the same as the widespread and aberrant notion that "cheap" (i.e. at or below the residual oil price) Mexican or Canadian supplies will gobble up the markets for Alaskan gas. Indeed, the cheaper these supplies the less they should interfere with the marketing of Alaskan gas!

The sponsors of the gasline proposal, moreover, assert that additional sales of Canadian gas will actually boost the financing prospects of the entire proposed pipeline system by enabling "pre-building" of the eastern leg (800 bcf/day) and portions of the western leg (200 bcf/day).

Thus, the Department of Energy's stated position on the desirability of importing large volumes of natural gas from Canada and Mexico is correct at least in principle (though we do not necessarily endorse the way in which the Department has implemented that position). Gas imports are indeed

AGO 559519

desirable, but at prices much higher than the cost of imported residual oil, they neither are a bargain for U. S. consumers, nor are they in the broader national interest. One of the reasons for the latter judgment is the adverse impact such imports would have on the marketability of Alaska gas.

In any case, institutional considerations may well have a greater effect on marketing perceptions and the "need" for Alaska gas than any theoretical arguments. If large quantities of Canadian and Mexican gas do become available and the outlook for continued shipments is reasonably secure, the "crisis" thinking behind the notion that Alaska gas is essential however much it may cost may well recede --- and with it, the willingness of transmission company sponsors to bear financial risks, the receptivity of federal and state regulatory bodies or Congress to sanction consumer risk-bearing, and ultimately the justification for federal involvement in the project's financing.

CONCLUSION

From a national viewpoint, it would be convenient if this kind of analysis led to definitive conclusions on the questions: "Will consumers end up paying more or less for Alaska gas if the project is delayed?" and "Might a crisis

develop in which the nation sorely regrets not having the gas (and potentially other Arctic supplies) available as soon as possible?"

From the standpoint of the state, a conclusion on whether royalty netbacks might benefit or suffer from delay would also be convenient. Likewise, both parties would be well served if some omniscient being could predict with certainty whether postponement of the pipeline construction and gas sales would change (1) how badly the project needs government assistance, and (2) the desires of other parties to bear financial risks.

This report, quite obviously, falls short of those goals. There is and can be no certain answer to these questions. Lack of certainty about what the future may bring (translated into "risks" by the financial community) has been one of the biggest stumbling blocks for this project all along, and it further promotes an atmosphere in which nobody wants to make commitments -- least of all government decisionmakers faced with the prospect of either consenting to certain extraordinary and potentially very unpleasant courses of action or being prepared to watch the project die, at least for the time being.

Nevertheless, the authors have attempted to stake out the bounds of the universe with respect to relevant questions,

and to attach some qualitative judgments on the prospects that various conditions will improve or deteriorate through time. Looking at how conditions may change with respect to volumes of gas available, project costs, and the marketing outlook, several broad conclusions are in order:

(1) The economic environment within which the pipeline must be justified and financed will probably not deteriorate with the passage of time. Likewise, prudent decision-making should not opt for delay based on the hope that future events will substantially sweeten the project's economics. While certainty about the project in some ways improve (for example, certainty about the volume of gas available), for the most part concern about events which may take place during the twenty-plus years of the project's operational life will not diminish whether the project is built tomorrow, ten, or twenty years from now. Uncertainty will always be with us.

(2) If the nation is truly concerned about domestic energy security, and if the state places an emphasis on the "present value" of its assets, it probably makes sense to encourage construction of the line now rather than later.

(3) While a further delay of one, two or more years will probably have measurable costs to the state and the nation, it is not likely to have catastrophic consequences for either of them, or for the eventual success of the project.

AGO 559523

SCOMM

#14:16

CHEM SYSTEMS INC.

PACIFIC RIM MARKET FOR PETROCHEMICALS

A Study For

Royalty Oil & Gas Advisory Board
Department of Natural Resources
State of Alaska

Chem Systems Inc.
747 Third Avenue
New York, NY 10017

October, 1979

AGO 559525

TABLE OF CONTENTS

		Page
I.	SUMMARY	1
	A. Introduction	1
	B. Market Characteristics	1
	1. U.S. West Coast	1
	2. Other U.S. and Canadian Markets	3
	3. Pacific Basin Markets	4
	C. Pacific Rim Petrochemical Markets	7
	1. Low Density Polyethylene	7
	2. High Density Polyethylene	9
	3. Polystyrene	10
	4. Polyvinyl Chloride	11
	5. Styrene	12
	6. Vinyl Chloride Monomer	13
	7. Ethylene Glycol	14
	8. Ethylene	15
	9. Polypropylene	15
	10. Phenol	16
	11. Acrylonitrile	17
	12. Isopropyl Alcohol	17
	13. Propylene	18
	D. Feasibility of an Alaskan Petrochemical Complex	18
II.	INTRODUCTION	20
III.	MARKET CHARACTERISTICS	21
	A. North American West Coast	21
	1. U.S. West Coast	21
	a. Background	21
	b. Petrochemical Overview	28
	2. Canadian West Coast	33
	a. Background	33
	B. Pacific Basin Market	36
	1. Japan	36
	a. Background	36
	b. Petrochemical Overivew	38
	2. Republic of Korea	42
	a. Background	42
	b. Petrochemical Overview	45
	3. Taiwan (Republic of China)	47
	a. Background	47
	b. Petrochemical Overview	50
	4. Hong Kong	53
	a. Background	53
	b. Petrochemical Overview	56
	5. Philippines	56
	a. Background	56
	b. Petrochemical Overview	61

TABLE OF CONTENTS (Cont'd)

	Page
6. Singapore	62
a. Background	62
b. Petrochemical Overview	64
7. Malaysia	65
a. Background	65
b. Petrochemical Overview	72
8. Thailand	73
a. Background	73
b. Petrochemical Overview	76
9. Indonesia	77
a. Background	77
b. Petrochemical Overview	81
10. People's Republic of China	82
a. Background	82
b. Petrochemical Overview	84
C. Factors Influencing Petrochemical Exports into the Pacific Basin Region	86
IV. PRODUCT ANALYSES	89
A. Low Density Polyethylene	89
1. West Coast Market	89
a. Demand	89
b. Supply	93
c. Captive Market	93
d. Pricing	94
2. Pacific Basin Market	94
a. Japan	94
b. Korea	97
c. Taiwan	99
d. Hong Kong	101
e. ASEAN Countries	102
f. People's Republic of China	103
3. Conclusions	103
B. High Density Polyethylene	105
1. West Coast Market	105
a. Demand	105
b. Supply	108
c. Captive Markets	109
d. Pricing	109
2. Pacific Basin Market	110
a. Japan	110
b. Korea	113
c. Taiwan	114
d. Hong Kong	115
e. ASEAN Countries	115
f. People's Republic of China	116
3. Conclusions	116

AGO 559527

TABLE OF CONTENTS (Cont'd)

	Page
C. Polystyrene	119
1. West Coast Market	119
a. Demand	119
b. Supply	121
c. Captive Market	121
d. Pricing	122
2. Pacific Basin Market	122
a. Japan	122
b. Korea	125
c. Taiwan	126
d. Hong Kong	126
e. ASEAN Countries	127
f. People's Republic of China	128
3. Conclusions	128
D. Polyvinyl Chloride	130
1. West Coast Market	130
a. Demand	130
b. Supply	133
c. Captive Market	133
2. Pacific Basin Market	134
a. Japan	134
b. Korea	137
c. Taiwan	138
d. Hong Kong	140
e. ASEAN Countries	140
f. People's Republic of China	141
3. Conclusions	141
E. Styrene	144
1. West Coast Market	144
a. Demand	144
b. Supply	146
c. Captive Market	146
d. Pricing	147
2. Pacific Basin Market	147
a. Japan	147
b. Korea	149
c. Taiwan	150
d. Hong Kong	150
e. ASEAN Countries	151
f. People's Republic of China	151
3. Conclusions	151
F. Vinyl Chloride Monomer	153
1. West Coast Market	153
a. Demand	153
b. Supply	154
c. Captive Market	154
d. Pricing	154

TABLE OF CONTENTS (Cont'd)

	Page
2. Pacific Basin Market	154
a. Japan	154
b. Korea	156
c. Taiwan	157
d. Hong Kong	158
e. ASEAN Countries	158
f. People's Republic of China	159
3. Conclusions	159
G. Ethylene Glycol	161
1. West Coast Market	161
a. Demand	161
b. Supply	162
c. Captive Market	162
d. Pricing	162
2. Pacific Basin Market	163
a. Japan	163
b. Korea	165
c. Taiwan	166
d. Hong Kong	167
e. ASEAN Countries	167
f. People's Republic of China	168
3. Conclusions	169
H. Ethylene	170
I. Polypropylene	171
1. West Coast Market	171
a. Demand	171
b. Supply	173
c. Captive Consumption	173
d. Pricing	173
2. Pacific Basin Market	173
a. Japan	173
b. Korea	176
c. Taiwan	177
d. Hong Kong	179
e. ASEAN Countries	180
f. People's Republic of China	181
3. Conclusions	181
J. Phenol	183
1. West Coast Market	183
a. Demand	183
b. Supply	185
c. Captive Market	185
d. Pricing	186
2. Pacific Basin Market	186
a. Japan	186
b. Korea	188
c. Taiwan	188

TABLE OF CONTENTS (Cont'd)

	Page
d. Hong Kong	188
e. ASEAN Countries	188
f. People's Republic of China	189
3. Conclusions	189
K. Acrylonitrile	191
1. West Coast Market	191
a. Demand	191
b. Supply	191
c. Captive Market	191
d. Pricing	191
2. Pacific Basin Market	191
a. Japan	191
b. Korea	194
c. Taiwan	194
d. Other Countries	194
3. Conclusions	195
L. Isopropyl Alcohol	196
1. West Coast Market	196
a. Demand	196
b. Supply	197
c. Captive Market	197
d. Pricing	197
2. Pacific Basin Market	197
a. Japan	197
b. Korea	199
c. Taiwan	199
d. Hong Kong	199
e. ASEAN Countries	199
f. People's Republic of China	200
3. Conclusions	200
M. Propylene	202
V. FEASIBILITY OF AN ALASKAN PETROCHEMICAL COMPLEX	203

I. SUMMARY

A. Introduction

There has been considerable interest in determining the feasibility of a petrochemical complex in Alaska due to the availability of large amounts of natural gas liquids (ethane, propane, and butanes) in the natural gas at Prudhoe. As part of their efforts, the Royalty Oil and Gas Development Advisory Board, Department of Natural Resources, State of Alaska, commissioned Chem Systems Inc. to prepare an analysis of the Pacific Rim markets for petrochemicals which could be produced from natural gas liquids. This area encompasses the western parts of the United States and Canada and the Far Eastern and Southeast Asian countries. The study entailed analyzing the market situations for those large volume basic petrochemicals, chemical intermediates, and plastic resins which are natural gas liquids derived and, based upon anticipated supply and demand relationships, market structure, etc., determining those products which could be produced in Alaska in world-scale facilities.

B. Market Characteristics

1. U.S. West Coast

The U.S. West Coast market encompasses the states of Alaska, California, Oregon, Washington, and Hawaii with a population of 29 million. Although these states account for 13 percent of U.S. population and 12 percent of value added by manufacture, they only account for about 2 percent of U.S. production of the major petrochemicals and 6 percent of overall U.S. chemical value added by manufacture. Most of the petrochemicals consumed within the region are supplied from facilities on the Gulf Coast.

The level of manufacturing activiites on the West Coast by SIC group is summarized in Table I-B-1. Although the percentage of value added within the region is roughly comparable to the West Coast's share of population, the distribution of manufacturing activities within the region

is substantially different than that for the U.S. The region is relatively important in food processing, lumber and wood, petroleum, and transporatation equipment (aircraft), while its activities in tobacco, textile mill products, fibers, chemicals, rubber, leather, automotive equipment and primary metals are substantially less than the U.S. average.

TABLE I-B-1

U.S. WEST COAST VALUE ADDED BY MANUFACTURE, 1975*
(Billion Dollars)

SIC Group		Total U.S.	U.S. West Coast	Percent of Total U.S.
20	Food & Kindred Products	48	7.5	16
21	Tobacco	4	-	-
22	Textile Mills Products	12	small	2
23	Apparel	15	2	12
24	Lumber & Wood	10	4	37
25	Furniture & Fixtures	6	1	13
26	Paper & Allied Products	18	2	13
27	Printing & Publishing	24	3	10
28	Chemicals	45	3	6
29	Petroleum & Coal	10	1.5	16
30	Rubber & Misc. Plastics	14	1	9
31	Leather & Leather Products	3	small	2
32	Stone, Clay & Glass	16	2	11
33	Primary Metal Industry	30	2	7
34	Fabricated Metal Products	35	3.5	11
35	Machinery Except Electrical	46	4	10
36	Electric & Electronic Equipment	35	5	14
37	Transportation Equipment	45	9.5	21
38	Instruments	14	2	12
39	Misc. Manufacturing Industries & Other	15	small	9
	Total	445	53	12

Source: Bureau of the Census, Annual Survey of Manufactures, 1975.

* Latest year for which information is available.

The West Coast is also an important agricultural center. The region is a major producer of fruits and vegetables, accounting for over half of U.S. production of a number of crops. However, it is a much less significant factor in grains.

Petrochemical consumption is related to both population and the nature and size of industrial and agricultural activities. Lack of major automobile, fiber, and synthetic rubber industries within the region means that the region is not significant in industries which account for about 20 percent of petrochemical consumption. This seriously affects products serving those industries such as polypropylene, and the major fiber and elastomer raw materials.

The important industries within the region are agriculture and related food processing applications, lumber and wood, transportation equipment (aircraft), and the electronics industry. Since agriculture and food processing are packaging-related industries, consumption of products such as low density polyethylene tends to be high. The large lumber, aircraft, boat building and electronics industries, unfortunately, are not large petrochemical consumers, although specific products, such as phenolic and unsaturated polyester resins, are used in sizeable quantities.

Lastly, there are some markets where the consumption is population related. This is true for large segments of the packaging industry, which is related to the demand for commodity resins, and certain other industries, such as coatings and inks, which are important consumers of materials such as solvents.

2. Other U.S. and Canadian Markets

In addition to supplying regional markets, a West Coast petrochemical facility is well located to supply adjacent regions in the U.S. and Canada. This encompasses those states and provinces west of the Rockies

and includes all or part of Arizona, Colorado, Idaho, Montana, Nevada, Utah, Wyoming and the Canadian province of British Columbia. These areas have a population of about 5 million, but, unfortunately, these areas are not significant consumers of petrochemicals.

3. Pacific Basin Markets

The Pacific Basin market, which encompasses Japan, Korea, Taiwan, Hong Kong and ASEAN countries of Philippines, Singapore, Malaysia, Thailand, and Indonesia, has a population of about 400 million.

Japan is the free world's second largest petrochemical producer, with a current basic petrochemical production of about 30 billion pounds per year, and other countries in the Pacific Basin consume over 2 billion pounds per year of petrochemicals. Key economic factors for these countries are summarized in Table I-B-2.

TABLE I-B-2

PACIFIC BASIN COUNTRY ECONOMIC GROWTH FACTORS

Country	1978 Population MM	1978 GNP MMM$	GNP Growth 1965-75	GNP Growth 1978-85	1978 Crude Oil Reserves MM Bbl	1978 Natural Gas Reserves MMM Ft^3
Japan	113	1,012	8.6	5	60	500
Korea	39	46	10.6	8	-	-
Taiwan	16	25	8.5	6-7	12	700
Hong Kong	5	14	6.7	5-6	-	-
ASEAN Countries						
Philippines	44	23	5.1	4-5	100	-
Singapore	2	8	10.4	7-8	-	-
Malaysia	12	16	6.5	5-6	2,800	17,000
Thailand	43	22	7.0	5-6	0.3	5,000
Indonesia	140	53	6.8	5-6	10,200	24,000

Japan is anticipated to have future growth approaching that of the U.S. and Europe due to loss of low oil costs, loss of cost competitiveness in labor-intensive industries, and major export market saturation. Overcapacity exists in petrochemicals, but domestic prices are relatively high due to high naphtha costs and the structure of the market. Although it traditionally has been difficult to export products to Japan for which ample domestic capacity exists, their high cost position can make it attractive to import products instead of producing them domestically.

Korea and Taiwan have experienced high economic growth and, in spite of current difficulties, good growth will continue since these countries are replacing Japan as low cost textile producers and they are building up their heavy industries. Both countries are in the process of building petrochemical industries which are justified on the basis of import substitution economics. These industries are protected by high duties and other trade barriers and thus imports are only possible for products for which local production is insufficient or under duty drawback situations.

Hong Kong is heavily oriented to textiles, electronics, and plastics fabrication. Dow's polystyrene plant is the only petrochemical plant in the Colony, and it is unlikely that any others will be built. No restriction or duties on petrochemical imports exist.

ASEAN Countries

The Association of Southeast Asian Nations (ASEAN) is attempting to promote an apportionment of facilities within the region coupled with a preferential duty structure. With respect to petrochemicals, the individual countries are promoting their projects, and rationalization of the situation within the next several years is unlikely. However, ultimately the basic goals of ASEAN are expected to be realized. Every country within the group, except Singapore, has significant protection for domestic industry such that petrochemical imports are limited to

those products whose local production is insufficient to meet demand and duty drawback situations.

The Philippines has a relatively poor growth outlook due to a continuing need for oil imports, the commodity nature of their exports, and the political situation. A petrochemical complex is planned, but it is unlikely to reach fruition for several years.

Singapore is a free port and has no duties and restrictions on petrochemical imports, essentially all of which are re-exported in the form of fabricated products. A large petrochemical complex consisting of an olefins unit and downstream units is planned by the Government in conjunction with Sumitomo and other Japanese firms, and it will be on stream in the early 1980s.

Malaysia has crude oil and gas reserves and could be the site of an export-oriented petrochemical complex in the future. Petrochemical consumption is relatively low, but steady growth is anticipated. The economy is dependent upon minerals and agricultural products, but the country benefits from a relatively stable political climate.

Thailand is primarily an agricultural country. Petrochemical consumption is modest, and the future growth outlook could be clouded by a potentially unstable political situation.

Indonesia has substantial crude oil and gas reserves, which may ultimately form the basis of a petrochemical industry. Petrochemical consumption is relatively modest but is capable of growing rapidly. Indonesia has the potential of replacing Korea and Taiwan as a center of low-cost labor in about a decade.

The Peoples' Republic of China was not analyzed in detail. The country has a population of about 900 million and has significant oil and natural gas reserves. A petrochemical industry, based on imported technology, is being developed. Petrochemical imports are anticipated to be modest since priority is being given to importation of plants and equipment.

C. Pacific Rim Petrochemical Markets

Those major petrochemicals which can be produced from natural gas liquids were examined. Materials whose production from natural gas liquids or whose markets are small were ignored. The products examined are as follows:

1. Basic petrochemicals (made directly from natural gas liquids).
   - ethylene
   - propylene

2. Major ethylene and propylene derivatives.
   - low density polyethylene
   - high density polyethylene
   - ethylbenzene/styrene
   - ethylene dichloride/vinyl chloride
   - ethlyene glycol
   - polypropylene
   - cumene/phenol
   - acrylonitrile
   - isopropyl alcohol

3. Other large-volume plastics.
   - polystyrene
   - polyvinyl chloride

1. Low Density Polyethylene

Low density polyethylene (LDPE) is the largest volume plastic resin. Most is made into film and bags, such as agricultural mulch film and trash bags. It is also used as the coating on milk cartons and as wire insulation. The current West Coast demand for this material is nearly 1 billion pounds while markets in the Pacific Basin are about 3 billion pounds, as shown in Table I-C-1. By 1985, Pacific Rim demand will approach 7 billion pounds.

TABLE I-C-1

LOW DENSITY POLYETHYLENE

	Demand				Capacity, per year	
	1978	1980	1990	AAGR, %*	1978	Future
		(Million Pounds)				
West Coast	935	1,660	2,320	7.9	140	0
		(Thousand Metric Tons)				
Japan	960	1,420	1,770	5.2	1,520	1,620
Korea	160	305	420	8.4	70	320
Taiwan	75	115	150	6.0	90	215
Hong Kong	90	115	135	3.4	0	0
ASEAN Countries	172	308	421	7.7	0	100**

* Average annual growth rate.
** Other projects possible.

At present Union Carbide, which has a small plant, is the only West Coast LDPE producer, while most resin used is brought into the region from the Gulf Coast. Due to the established position of existing suppliers and some captive consumption, an Alaskan producer could only reasonably expect to capture about 15-20 percent of the merchant market which would equate to about 250 and 350 million pounds in 1985 and 1990, respectively. Hong Kong and the ASEAN countries will be major importers of LDPE during the 1980s, and Japan could become an importer due to its poor petrochemical cost postion.

World-scale LDPE plants during the 1980s will be at least 500 million pounds per year in size. Based upon market opportunities on the West Coast and substantial export opportunities to the Pacific Basin, an LDPE plant in Alaska is viable from a market standpoint.

2. High Density Polyethylene

High density polyethylene (HDPE) is used in the manufacture of bleach and other bottles. A rapidly developing use is in the production of thin film, where it is replacing LDPE and paper. The current West Coast demand is about 500 million pounds while markets in the Pacific Basin area are about 1.5 billion pounds, as shown in Table I-C-2. By 1985, Pacific Rim demand will approach 4 billion pounds.

TABLE I-C-2

HIGH DENSITY POLYETHYLENE

	Demand				Capacity, per year	
	1978	1985	1990	AAGR, %	1978	Future
	(Million Pounds)					
West Coast	500	1,065	1,610	10.3	0	0
	(Thousand Metric Tons)					
Japan	438	780	970	7.0	882	982*
Korea	60	140	205	10.1	35	105
Taiwan	45	80	115	8.1	50	170
Hong Kong	30	48	63	6.4	0	0
ASEAN Countries	115	208	297	8.2	0	80**

* Future projects not certain.
** Additional facilities possible.

The competitive factors in the West Coast market are similar to those for LDPE. As a result, an Alaskan producer could only reasonably expect to capture about 20 percent of the merchant market, or about 200 and 300 million pounds in 1985 and 1990, respectively.

Hong Kong, the ASEAN countries and Korea will be major HDPE importers during the 1980s and Japan also could become a significant importer due to its poor cost position.

World-scale HDPE plants during the 1980s will be at least 250 million pounds per year in size. Based upon market opportunities on the West Coast and in the Pacific Basin, an HDPE facility is viable from a market standpoint.

3. Polystyrene

Polystyrene is used in the manufacture of foamed plastic cups, refrigerator door liners, and toys. The current West Cost demand is nearly 600 million pounds while markets in the Pacific Basin are about 3 times as large, as shown in Table I-C-3. By 1985, Pacific Rim demand will be about 3.5 billion pounds.

TABLE I-C-3

POLYSTYRENE

	Demand				Capacity, per year	
	1978	1985	1990	AAGR, %	1978	Future
		(Million Pounds)				
West Coast	555	830	1,060	5.5	480	550*
		(Thousand Metric Tons)				
Japan	570	825	1,030	5.1	739	739*
Korea	70	125	165	7.4	50	118*
Taiwan	58	110	135	7.3	70	70*
Hong Kong	100	170	220	6.8	65	125
ASEAN Countries	54	110	212	10.6	39	47*

* Additional expansions likely.

At present most polystyrene consumed on the West Coast is produced locally. The same situation exists in the Pacific Basin since polystyrene resins are relatively easy to manufacture and it is easier to ship the styrene monomer than the resin itself. As a result, polystyrene manufacture in Alaska does not appear very attractive.

4. Polyvinyl Chloride

Polyvinyl chloride (PVC) is used to produce plastic pipe for agricultural and telecommunications use. It is also used to make vinyl floor tiles, shower curtains, upholstery, etc. The current West Coast demand for PVC is about 700 million pounds while the Pacific Basin market is over 4 billion pounds. By 1985, Pacific Rim demand will approach 8 billion pounds, as shown in Table I-C-4.

TABLE I-C-4

POLYVINYL CHLORIDE

	Demand				Capacity, per year	
	1978	1985	1990	AAGR, %	1978	Future
		(Million Pounds)				
West Coast	695	1,330	1,890	8.7	370	370
		(Thousand Metric Tons)				
Japan	1,180	1,660	2,060	4.8	1,921	1,921*
Korea	185	350	460	7.9	200	200*
Taiwan	330	535	695	6.4	428	452*
Hong Kong	50	73	89	4.9	0	0
ASEAN Countries	135	275	415	8.8	151	221*

* Additional expansions likely.

At present about half of the PVC used on the West Coast is produced locally while the remainder is shipped from the Gulf Coast. Countries within the Pacific Basin are anticipated to be virtually self-sufficient in PVC, which provides little opportunity for exportation from an Alaska plant. During the 1980s, new polyvinyl chloride facilities will have to be at least 200 million pounds per year in size in order to be competitive. The output of such a facility could be sold in West Coast markets, but it is generally preferable for a firm to locate the facility closer to the markets and ship vinyl chloride monomer.

5. Styrene

Styrene is a chemical intermediate which is used for the production of polystyrene, ABS, and unsaturated polyester resins. It is also used for the production of SBR rubber. The current West Coast and Pacific Basin demand for styrene is about 650 million and 3 billion pounds, respectively. By 1985, the overall Pacific Rim market will reach 7 billion pounds, as shown in Table I-C-5.

TABLE I-C-5

STYRENE

	Demand				Capacity, per year	
	1978	1985	1990	AAGR, %	1978	Future
		(Million Pounds)				
West Coast	639	1,003	1,340	6.4	0	0
		(Thousand Metric Tons)				
Japan	1,112	1,540	1,920	4.8	1,550	1,780*
Korea	75	167	235	10.0	60	185
Taiwan	81	162	201	7.9	100	200
Hong Kong	74	125	125	4.5	0	0
ASEAN Countries	25	75	125	14.3	0	0

* Additional expansions likely.

About half of the West Coast market is captive while the remainder of the market is primarily represented by unsaturated polyester resin producers who purchase primarily on price. In the Pacific Basin, Korea and Taiwan will be basically self-sufficient in styrene while the remainder of the market is largely in the hands of Dow Chemical and Japanese firms.

During the 1980s, it is expected that a styrene plant will have to be at least 600-800 million pounds per year in size in order to be competitive. Production of styrene or its precursor, ethylbenzene, is

viable in Alaska, but most likely only by those firms which have a strong captive position in styrene derivatives within the Pacific Rim area. Production of styrene also would require a source of benzene, which could become available from the proposed Alpetco facilities or the large complex envisioned in Alberta.

6. Vinyl Chloride Monomer

Essentially all vinyl chloride monomer is used in the production of PVC resins. In 1978 West Coast demand was 335 million pounds while the Pacific Basin demand approached 5 billion pounds. By 1985 Pacific Rim demand will reach 7.5 billion pounds, as shown in Table I-C-6.

TABLE I-C-6

VINYL CHLORIDE MONOMER

	Demand*				Capacity, per year	
	1978	1985	1990	AAGR, %	1978	Future
		(Million Pounds)				
West Coast	335	500-600	500-600	-	175	175**
		(Thousand Metric Tons)				
Japan	1,370	1,970	2,410	4.8	2,191	2,666
Korea	200	360	470	7.4	78	430
Taiwan	400	615	785	5.8	360	700
Hong Kong	0	0	0	0	0	0
ASEAN Countries	120	235	365	9.7	0	0

* In part dependent upon new PVC facilities.
** Plant may shut down.

Vinyl chloride is manufactured from ethylene and chlorine. Chlorine is an energy-intensive product and its production also entails the marketing of large quantities of coproduct caustic soda. Due to the high energy consumption and the chlorine/caustic soda imbalance in Japan and Taiwan, firms in these countries are anticipated to import significant quantities of vinyl chloride and its precursor, ethylene dichloride. This imbalance

does not exist on the West Coast, where large quantities of caustic soda are required by the paper industry. In addition to market opportunities in the Pacific Basin, a large part of the West Coast vinyl chloride market should be available to an Alaskan producer. Basically, there are markets in the Pacific Rim Area for the output of an 500 million-1 billion pound per year world-scale facility.

7. Ethylene Glycol

Ethylene glycol is used as an antifreeze on the West Coast while the product's other major end-use, the manufacture of polyester fiber, is the predominate market for the product in the Pacific Basin countries. The 200 million pound per year West Coast market is small, and it consists primarily of branded antifreeze products. The Pacific Basin market is currently 1.5 billion pounds, and it is forecast to reach nearly 2.4 billion pounds by 1985, as shown in Table I-C-7.

TABLE I-C-7

ETHYLENE GLYCOL

	Demand				Capacity, per year	
	1978	1985	1990	AAGR, %	1978	Future
	(Million Pounds)					
West Coast	200	232	248	1.8	0	0
	(Thousand Metric Tons)					
Japan	410	575	675	4.2	575	675
Korea	80	158	220	8.8	0	80
Taiwan	120	240	300	8.0	175	225
Hong Kong	neg.	neg.	neg.	-	0	0
ASEAN Countries	69	98	126	5.3	0	120

In the mid-1980s, most Pacific Basin countries will be significant importers of ethylene glycol, and it may be advantageous for Japanese firms to import the material due to their relatively poor cost position. Production of ethylene glycol in a world-scale 400-500 million pound per year plant would be viable for a firm or group of firms which had a strong position in the product within the Pacific Basin area.

8. Ethylene

The primary use for ethylene is for the production of derivatives in adjacent facilities. However, modest quantities are currently shipped in cryogenic tankers in Japan and Europe (the product boils at -119°F). The only market sufficient to take the output from a 1 to 1.5 billion pound per year world-scale plant would be Japan. However, the Japanese would prefer to import derivatives. Petrochemical complexes are being planned for the Phillipines and Thailand, which would utilize liquid ethylene as the feedstock. Potential requirements would be about 500 million pounds per year. This demand could be met from Alaska, but actual completion of the projects is highly uncertain, and over the longer term replacement of imports with local production is likely.

9. Polypropylene

Polypropylene is used in the manufacture of plastic straws, automobile interior door panels, fiber and film. Demand on the West Coast was only 130 million pounds in 1978 since many major uses for the product do not exist in the area. Pacific Basin demand was about 2 billion pounds, as shown in Table I-C-8. By 1985, demand is expected to reach 3.5 billion pounds.

TABLE I-C-8

POLYPROPYLENE

	Demand				Capacity, per year	
	1978	1985	1990	AAGR, %	1978	Future
	(Million Pounds)					
West Coast	130	260	375	9.1	0	0
	(Thousand Metric Tons)					
Japan	577	855	1,045	5.1	1,131	1,331
Korea	131	245	330	8.0	70	150
Taiwan	74	155	225	9.7	50	180
Hong Kong	18	33	41	7.1	0	0
ASEAN Countries	105	209	303	9.2	20	100-200*

* Future projects not certain.

The significant polypropylene markets are in the Pacific Basin, where an Alaskan plant would face strong competition from the large Japanese producers. Polypropylene production does not look attractive, except possibly for selected Japanese firms with a strong position in the Pacific Basin.

10. Phenol

Phenol is primarily used for the production of phenolic adhesives for plywood and other forest products. In the Pacific Basin countries, phenolic resins are not generally used in plywood manufacture. The West Coast market for phenol is currently about 300 million pounds while the Pacific Basin market is only 500 million pounds, as shown in Table I-C-9. By 1985, the overall market will reach 1.2 billion pounds.

TABLE I-C-9

PHENOL

	Demand				Capacity, per year	
	1978	1985	1990	AAGR, %	1978	Future
		(Million Pounds)				
West Coast	305	430	520	4.5	140	165
		(Thousand Metric Tons)				
Japan	202	295	405	6.0	316	416
Korea	10	24	35	11.0	0	0
Taiwan	8	18	24	9.6	0	0
Hong Kong	neg.	neg.	neg.	-	0	0
ASEAN Countries	12	18	23	5.5	0	0

The West Coast market is largely captive and the Pacific Basin market is relatively small; thus, marketing the output from a world-scale 400-500 million pound per year unit is not feasible.

11. Acrylonitrile

Acrylonitrile is primarily used for the production of acrylic fibers and ABS resins. The West Coast acrylonitrile market is negligible while the Pacific Basin market was about 1.6 billion pounds in 1978. It should increase to 2.3 billion pounds by 1985, as shown in Table I-C-10.

TABLE I-C-10

ACRYLONITRILE

	Demand				Capacity, per year	
	1978	1985	1990	AAGR, %	1978	Future
	(Million Pounds)					
West Coast	8	10	13	4.2	0	0
	(Thousand Metric Tons)					
Japan	515	700	860	4.4	744	744
Korea	124	190	240	5.7	77	177
Taiwan	84	154	198	7.4	132	132*
Hong Kong	neg.	neg.	neg.	-	0	0
ASEAN Countries	neg.	neg.	neg.	-	0	0

* Additional facilities expected.

There is a large excess of acrylonitrile capacity on the Gulf Coast, and the Pacific Basin countries are adequately supplied with regional production. As a result, an Alaskan facility would not be attractive.

12. Isopropyl Alcohol

Isopropyl alcohol is used as a solvent and for the production of acetone. The West Coast isopropyl alcohol demand was 165 million pounds in 1978 while the Pacific Basin market was of comparable size. By 1985, the overall market should reach 500 million pounds, as shown in Table I-C-11.

TABLE I-C-11

ISOPROPYL ALCOHOL

	Demand				Capacity, per year	
	1978	1985	1990	AAGR, %	1978	Future
	(Million Pounds)					
West Coast	165	198	220	2.4	215	215
	(Thousand Metric Tons)					
Japan	65	83	95	3.2	105	105
Korea	2	3	3	-	0	0
Taiwan	1	32	32	-	0	30
Hong Kong	2	3	4	-	0	0
ASEAN Countries	7	11	15	6.6	0	0

Since demand for the product is relatively small and adequate capacity exists, isopropyl alcohol production in Alaska is not viable.

13. Propylene

Propylene is primarily used for the production of derivatives at adjacent or nearby sites. Although the product is easier to ship than ethylene, large-scale exportation is generally not practiced, although Korea is a significant importer at present and a project based on imported propylene is envisioned for the Philippines. It is anticipated that adequate supply will exist in the Pacific Rim area and thus large shipments from Alaska would not be viable from a market standpoint.

D. Feasibility of an Alaskan Petrochemical Complex

The core of a natural gas liquids based petrochemical complex is an olefins plant which produces ethylene as the prime product. The simplest and lowest cost olefin units are based on ethane feed. If propane and/or butane are used as the feedstock instead of ethane, significant quantities of propylene are also produced.

In order for a petrochemical complex to be viable, a sufficient volume of derivatives must be produced to utilize the production from a world-scale

olefins unit. The economic size is at least 1 billion pounds per year of ethylene capacity.

The manufacture of low and high density polyethylene, styrene, vinyl chloride, and ethylene glycol in world-scale units were found to be viable. Table I-D-1 summarizes the potential ethylene consumption by derivative.

TABLE I-D-1

POTENTIAL ETHYLENE CONSUMPTION BY DERIVATIVE
(Million Pounds Per Year)

Derivative	Derivative Plant Size	Ethylene Consumption at Capacity
Low Density Polyethylene	500	525
High Density Polyethylene	250-400	260-420
Styrene	600-800	200-270
Vinyl Chloride	500-1,000	250-500
Ethylene Glycol	400-500	320-400
		1,555-2,115

Based on the market situations, an Alaskan petrochemical complex would most likely consist of low and high density polyethylene facilities plus a styrene, vinyl chloride, or ethylene glycol plant. The actual units considered would primarily be dictated by the nature of the specific firms involved in the project.

The market for propylene derivatives does not look very good. However, if it is necessary to use propane and/or butanes as part of the feed, a 200 million pound per year polypropylene plant probably would be viable.

Basically, the petrochemical markets in the Pacific Rim area are sufficient to support a major complex in Alaska at present and probably a second complex in the late 1980s.

AGO 559549

II. INTRODUCTION

The natural gas at Prudhoe contains large amounts of natural gas liquids (ethane, propane and butanes). These materials are desirable feedstocks for the production of a range of petrochemicals. As a result, there has been considerable interest in determining the feasibility of a petrochemical complex in Alaska based upon utilization of these materials. Such a complex would provide steady long-term employment and help diversify the Alaskan economy.

As part of their efforts, the Royalty Oil and Gas Development Advisory Board, Department of Natural Resources, State of Alaska, commissioned Chem Systems Inc. to prepare an analysis of the Pacific Rim markets for petrochemicals which could be produced from natural gas liquids. This area encompasses the western parts of the United States and Canada and the Far Eastern and Southeast Asian countries. The study entailed analyzing the market situations for those large volume basic petrochemicals, chemical intermediates, and plastic resins which are natural gas liquids derived and, based upon anticipated supply and demand relationships, market structure, etc., determining those products which could be produced in Alaska in world-scale facilities.

III. MARKET CHARACTERISTICS

A. North American West Coast

1. U.S. West Coast

a. Background

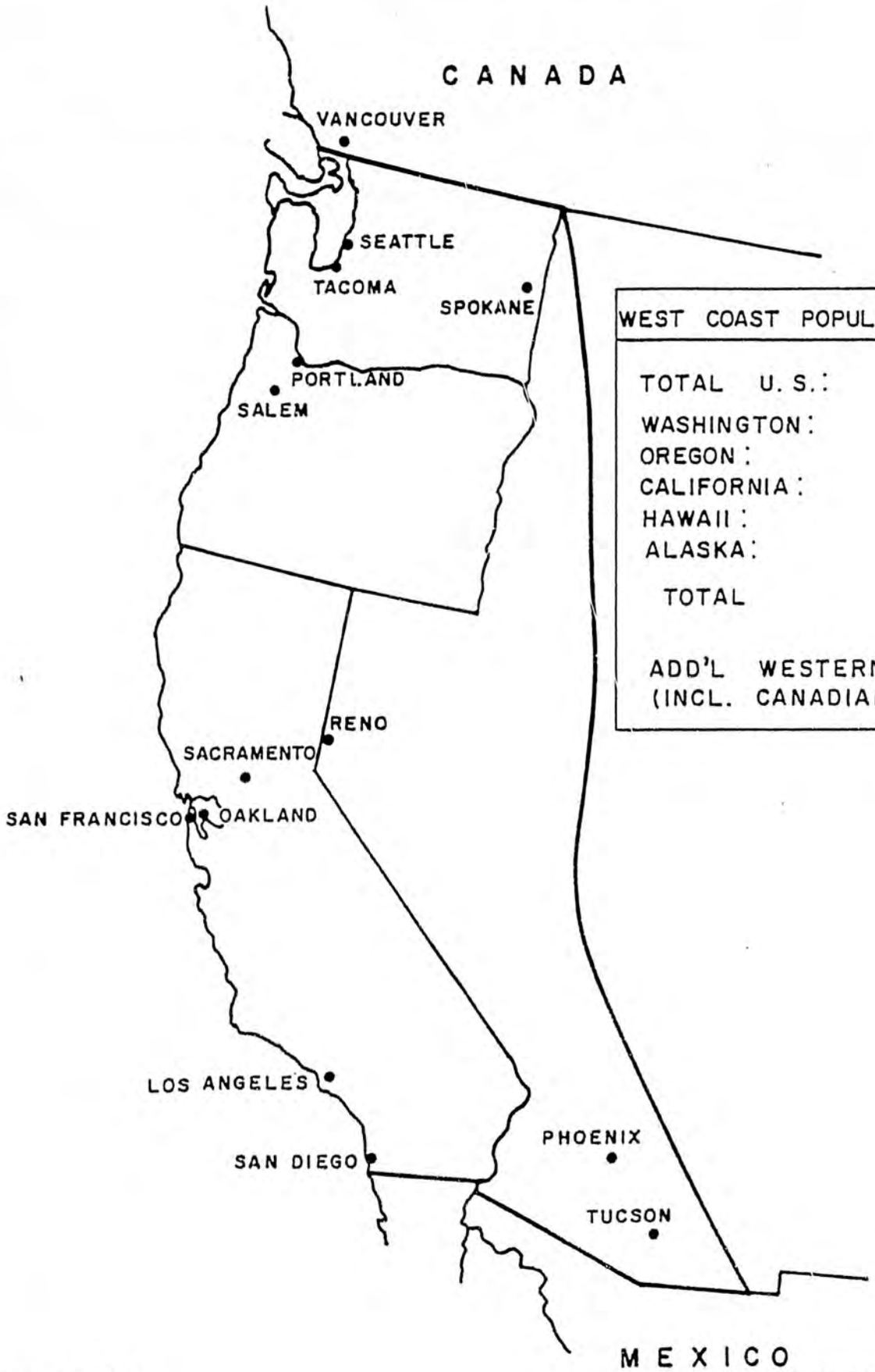
The U.S. West Coast has always had the distinction of being part of, yet somewhat separate from, the overall U.S. market, which is concentrated east of the Rockies. This is due to the mountains and to considerable distances separating the region from other major population and industrial centers. The Pacific or West Coast Region is considered that area to the West of the Sierra Nevada mountains and the Cascade Range. Within the Pacific region is California, the largest state, with Oregon and Washington to the north. Also included for purposes of this report, but of relatively small impact, are Hawaii and Alaska. The area adjacent to the Pacific region, between the Rockies and the Pacific region, is the so-called Mountain Region. The two most populated states in this region are Colorado and Arizona, and they can be considered adjunct markets to the West Coast Pacific Region. A map showing the region is presented in Figure III-A-1.

Population

The population of the West Coast Region in 1977 was about 29.3 million, of which 28.0 live in California, Oregon and Washington. The regional total equals about 13.5 percent of the U.S. population of 217 million. The population breakdown by state in the West Coast Region is also indicated in Figure III-A-1. California is by far the largest market with 75 percent of West Coast population.

By 1980 and 1985, if the 1960-1970 migration patterns within the United States continue, the percentage of population in the West Coast region will rise from 12.5 percent of the U.S. total in 1977 to 14.0 percent in 1980 and 14.4 percent in 1985, as shown in Table III-A-1.

FIGURE III – A – 1



WEST COAST POPULATION BREAKDOWN	
TOTAL U. S.:	213 MM
WASHINGTON:	3.5 MM
OREGON:	2.3 MM
CALIFORNIA:	21.2 MM
HAWAII:	0.9 MM
ALASKA:	0.4 MM
TOTAL	28.3
ADD'L WESTERN MARKETS (INCL. CANADIAN):	5 MM

AGO 559552

CHEM SYSTEMS INC.
PROJECT NO. 527 DATE

In 1985, West Coast population is anticipated to reach 34.5 million, a growth of 22 percent over the decade in contrast to a U.S. growth of only 12 percent.

TABLE III-A-1

U.S. WEST COAST POPULATION PROJECTIONS

	1977	1980	1985	AAGR, %*
Total U.S.	216.8	226.9	239.3	1.2
U.S. West Coast	29.3	31.8	34.5	2.0
West Coat, % of U.S.	13.5	14.0	14.4	

* Average annual growth rate.

Although the population of the West Coast is larger than that of many countries with fair-sized petrochemical industries, such as Canada, Australia and the Benelux countries, it still is relatively small and spread out by U.S. standards. For instance, the East Coast market, which is shown in Figure III-A-2, is roughly comparable in size, but has nearly three times the population.

Manufacturing and Agricultural Activities

In 1975, the latest year for which statistics are available, value added by manufacture on the West Coast totaled about $53 billion, or 12 percent of the overall U.S. figure of $445 billion. This percentage is roughly comparable to the West Coast's share of population. However, the distribution of manufacturing activities within the region is substantially different than that for the U.S., as is shown in Table III-A-2. The region is relatively important in food processing, lumber and wood, petroleum and transportation equipment, while its activities in tobacco, textile mill products, chemicals, leather and primary metals are substantially less than the U.S. average. In addition, in most industrial segments, the distribution of activities within a segment is considerably different from that in the country as a whole. For instance, the West Coast's share of electrical and electronic equipment

FIGURE III – A – 2

DEMOGRAPHIC STATISTICS

TOTAL U.S. POPULATION:	213 MM
NEW ENGLAND MARKET:	12 MM
MIDDLE ATLANTIC MARKET:	48 MM
SOUTHEAST U.S. MARKET:	29 MM
WEST COAST MARKET:	28 MM

AGO 559554

CHEM SYSTEMS INC.
PROJECT NO. 527 DATE

manufacture is in line with its share of the population, but in the West Coast this market consists almost entirely of the electronics segment of this market. The situations for the major manufacturing industries are briefly described below.

TABLE III-A-2

U.S. WEST COAST VALUE ADDED BY MANUFACTURE, 1975*
(Billion Dollars)

SIC Group		Total U.S.	U.S. West Coast	Percent of Total U.S.
20	Food and Kindred Products	48	7.5	16
21	Tobacco	4	-	-
22	Textile Mill Products	12	small	2
23	Apparel	15	2	12
24	Lumber and Wood	10	4	37
25	Furniture and Fixtures	6	1	13
26	Paper and Allied Products	18	2	13
27	Printing and Publishing	24	3	10
28	Chemicals	45	3	6
29	Petroleum and Coal	10	1.5	16
30	Rubber and Misc. Plastics	14	1	9
31	Leather and Leather Products	3	small	2
32	Stone, Clay and Glass	16	2	11
33	Primary Metal Industry	30	2	7
34	Fabricated Metal Products	35	3.5	11
35	Machinery, except Electrical	46	4	10
36	Electric and Electronic Equipmnt	35	5	14
37	Transportation Equipment	45	9.5	21
38	Instruments	14	2	12
39	Misc. Manufacturing Industries and Others	15	small	9
	Total	445	53	12

Source: Bureau of the Census, Annual Survey of Manufactures, 1975.

* Lastest year for which information is available.

Food and Kindred Products (SIC 20) is the second largest industry within the region, with a value added of $7.5 billion. It consists of the large canned, frozen and dehydrated food industries throughout the region which serve both regional and national markets. Also included is the California wine industry, which represents about 7 percent of the total.

Tobacco (SIC 21) and Textile Mill Products (SIC 22) industries are relatively small in the region, with the tobacco industry being virtually non-existent and the California textile industry accounting for less than 2 percent of the U.S. total.

The Apparel (SIC 23) industry of the region is about in line with its population percentage. The industry is primarily concentrated in California, although there are small operations in Oregon, Washington and Hawaii.

The $4 billion Lumber and Wood (SIC 24) industry on the West Coast represents over one-third of the U.S. total. California, Oregon and Washington each represent over $1 billion in value added in their plywood, saw mill and related operations.

The Furniture and Fixtures (SIC 25) industry of the West Coast represents its share of the U.S. total. It is concentrated in California, which represents 85-90 percent of the regional total of about $800 million. The Paper and Allied Products (SIC 26) and Printing and Publishing (SIC 27) industries also represent the West Coast share of the population.

The Chemical (SIC 28) industry is also concentrated in California. The soaps and detergents, toilet goods, pharmaceutical and inorganic chemical segments are relatively important, while the basic and intermediate petrochemical segments are relatively small.

The $1.5 billion Petroleum and Coal (SIC 29) activity is due to the West Coast refinery industry. Rubber and Miscellaneous Plastics (SIC 30) is primarily accounted for by the California plastics fabrication industry, although there is some tire manufacture within the region.

The Leather (SIC 31) industry is insignificant within the region, but the Stone, Clay and Glass (SIC 32) industry is in line with the region's population percentage. This segment includes gypsum, cement and concrete.

The Primary Metal Industry (SIC 33) is relatively small within the region, representing only 7 percent of the U.S. total. A significant part of this segment is aluminum smelting in Washington and Oregon. Fabricated Metal Products (SIC 34), on the other hand, is more in line with population share due to the aircraft and construction activities within the region.

Machinery, except Electrical (SIC 35) consists of industrial machinery and computers, which account for about a third of the regional total of $4 billion. Electric and Electronic Equipment (SIC 36) consists of essentially all other electrical and electronic equipment. As a result, these classifications tend to understate the importance of the region's electrical and electronics industry, which is about 16-17 percent of the nation's total. This industry is centered in California.

Transportation Equipment (SIC 37) is the largest industry on the West Coast with value added of $9.5 billion, over 21 percent of the U.S. total. Most of this total is accounted for by the aircraft industry in California and Washington.

The regional total for Instruments (SIC 38) and Miscellaneous Manufacturing Industries (SIC 39), which includes toys and jewelry, tend to be in line with population share.

In addition to manufacturing activities, the West Coast is an important agricultural center. Commercial vegetable production is over half the U.S. total, with the region supplying most of the country for the winter months. Fruits are also important, with the regional production of some important products such as apples and peaches representing over 40 percent of U.S. production. The region is much less a factor in grain production, although wheat, barley and rice production are significant.

Markets for Petrochemicals

Due to the differences between the composition of the industrial and agricultural activities of the West Coast relative to the overall U.S.,

petrochemical demand estimates based strictly upon per capita consumption are very misleading. Among the most important markets for petrochemicals are the automobile, fiber, synthetic rubber and the chemical industry itself. Figure III-A-3 shows the historical location of these industries and indicates that the West Coast is not an important location for them. There is no indication that the existing situation will change in the next several years, if ever. This means that regional demand for certain plastic resins, such as acrylonitrile-butadiene-styrene and polypropylene, which are oriented to the automobile and appliance industries, will be small. Likewise, the lack of fiber and synthetic rubber industries means that there is essentially no demand for key raw materials for these industries, such as acrylonitrile and butadiene. The chemical industry has historically been its own best customer. The lack of a large chemical industry means that demand for chemical intermediates tends to be rather low.

The important industries within the region are agriculture and related food processing applications, lumber and wood, transportation equipment and the electronics industry. Since agriculture and food processing involve packaging, consumption of materials such as low density polyethylene would tend to be higher. The large lumber, aircraft, boat building and electronics industries, unfortunately, are not large petrochemical consumers, although consumption of specific products such as phenolic, unsaturated polyester and epoxy resins would tend to be relatively high.

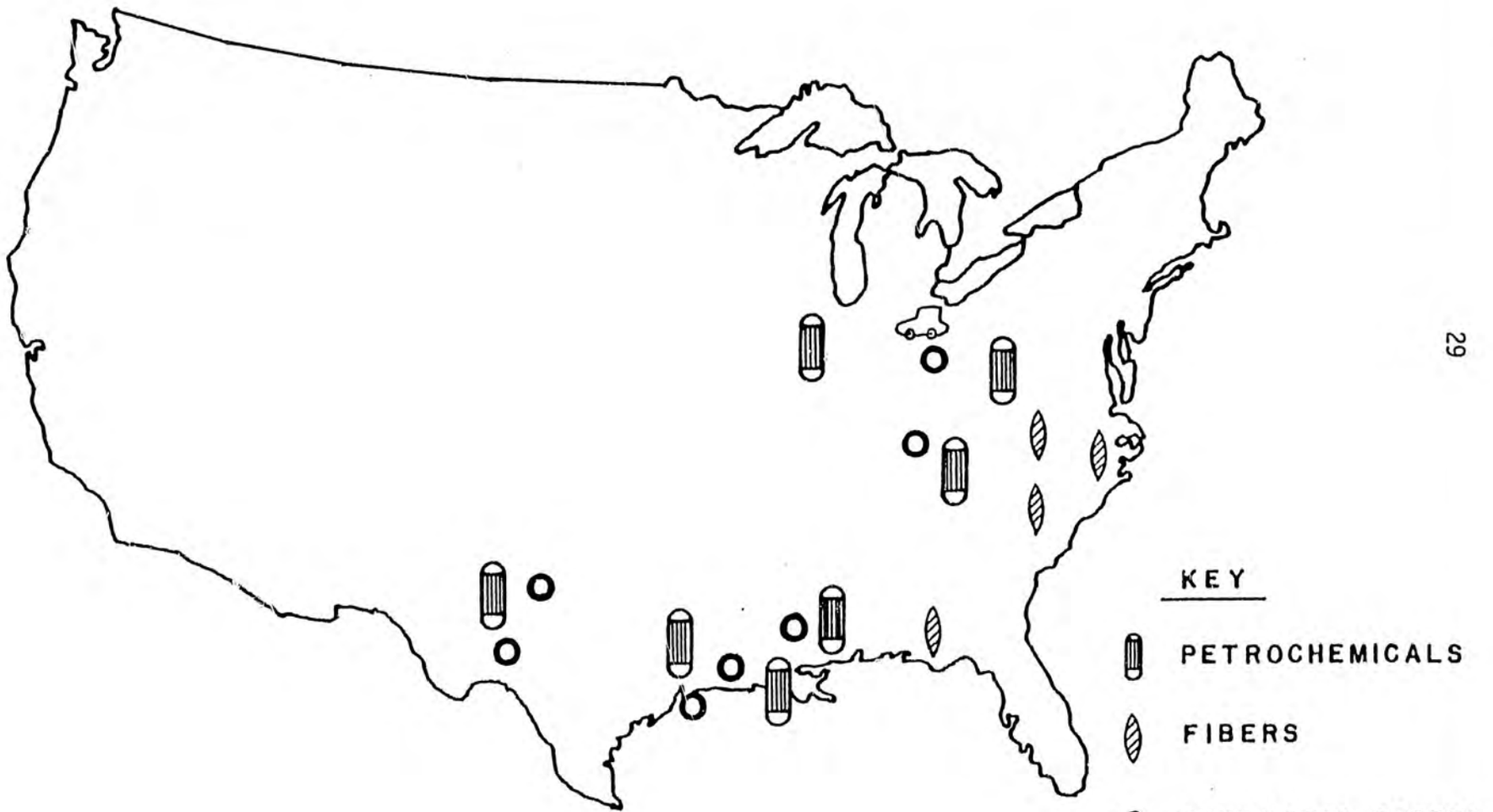
Lastly, there are some markets where the consumption is population related. This is true for large segments of the packaging industry, which is related to the demand for commodity resins and certain other industries, such as coatings and inks, which are important consumers of materials such as solvents.

b. Petrochemical Overview

This section presents an overview of the existing West Coast petrochemical industry. Detailed information on specific products is presented in Section IV of this report.

FIGURE III – A – 3

IMPORTANT GEOGRAPHICAL MARKETS FOR PRIMARY PETROCHEMICALS & INTERMEDIATES



CHEM SYSTEMS INC.
PROJECT NO. 5 2 7 DATE

AGO 559559

The existing petrochemical industry on the West Coast is quite small. A number of important petrochemicals, such as butadiene, the elastomers and many resins, are not produced within the region. For those products which are produced, regional capacity generally averages less than 5 percent of the U.S. total.

At present, most of the petrochemical industry is centered around Los Angeles. In addition, Chevron has some derivative facilities at its Richmond (San Francisco Bay) site. There are also carbon black plants in the desert and there is one petrochemical plant in Washington. A list of the petrochemical plants within the region is shown in Table III-A-4, and the locations for these facilities are shown in Figure III-A-1.

Basic petrochemical production is very small. Ethylene is obtained from refinery gas by Union Carbide and Arco. In addition, Shell and Chevron utilize refinery propylene in derivative production. Regional capacity for these olefins is only about 1 percent of the U.S. total. Both Arco and Chevron have reformer benzene facilities to meet regional needs. In addition, Chevron has ortho and para-xylene facilities designed to serve regional, U.S. and export markets. Carbon black is produced by three firms in facilities designed to meet regional needs.

Only seven intermediate petrochemicals are produced within the region (vinyl chloride, ethyl chloride, isopropyl alcohol, acetone, phthalic anhydride, cumene and phenol). This is a small percentage of the approximately 30 intermediates which are produced in significant volume. These intermediates are consumed within the region, with the region being self-sufficient in ethyl chloride, isopropyl alcohol, acetone, phthalic anhydride and cumene.

Low density polyethylene is the only polyolefin resin produced on the West Coast. The output from the Union Carbide facility satisfies less than 20 percent of regional demand. On the other hand, most of the West Coast polyvinyl chloride and polystyrene resin demand is met with production from within the region.

TABLE III-A-4

EXISTING U.S. WEST COAST PETROCHEMICAL FACILITIES
(Million Pounds per Year)

Product	Company	Location	Capacity	% of U.S. Capacity
Basic Petrochemicals				
Ethylene (from refinery gas)	Arco	Wilmington, CA	100	
	Union Carbide	Torrance, CA	170	
			270	1
Propylene (from refinery gas)	Shell	Dominquez, CA	100	
	Chevron	Richmond, CA	200	
		El Segundo, CA	100	
			400	2
Benzene (reformer)	Arco	Wilmington, CA	14*	
	Chevron	El Segundo, CA	15	
			29*	1
o-Xylene	Chevron	Richmond, CA	150	10
p-Xylene	Chevron	Richmond, CA	110	2
Carbon black (furnace)	Ashland	Mojave, CA	60	
	Cities Service	Mojave, CA	53	
	Continental Carbon	Bakersfield, CA	77	
			190	5
Intermediates & Solvents				
Vinyl chloride monomer	Stauffer Chemical	Watson, CA	175	2
Cumene	Chevron	El Segundo, CA	100	2
Phenol	Chevron	Richmond, CA	50	
	Ferro	Santa Fe Springs, CA	2	
	Kalama	Kalama, WA	75	
			127	4

* Million gallons.

AGO 559561

CHEM SYSTEMS INC.

AGO 559562

TABLE III-A-4 (Cont'd)

Product	Company	Location	Capacity	% of U.S. Capacity
Intermediates & Solvents				
Phthalic anhydride	Allied Chemical	El Segundo, CA	36	
	Chevron	Richmond, CA	50	
			86	7
Isopropyl alcohol	Shell Chemical	Dominquez, CA	210	8
Acetone	Shell Chemical	Dominquez, CA	100	
	Chevron	Richmond, CA	33	
			133	4
Ethyl chloride	Stauffer Chemical	Long Beach, CA	100	14
Plastic Resins				
Low density polyethylene	Union Carbide	Torrance, CA	140	2
Polyvinyl chloride	B.F. Goodrich	Long Beach, CA	150	
	Keysor Century	Saugus, CA	50	
	Stauffer Chemical	Carson, CA	140	
			340	5
Polystyrene	A&E Plastik	City of Industry, CA	45	
	Dow Chemical	Torrance, CA	200	
	Monsanto	Long Beach, CA	50	
	Amoco Chemical	Torrance, CA	35	
	Sterling Plastics	Los Angeles, CA	60	
	Mobil Chemical	Santa Ana, CA	30	
			420	8

2. Canadian West Coast

a. Background

British Columbia is the most Westerly province of Canada. It has an area of 366,255 square miles, including 6,976 square miles of freshwater lakes. It ranks third in size among the ten provinces. Its length from north to south is 760 miles; its average width from west to east is over 400 miles. The Yukon Territory and the Northwest Territories lie to the north of the province, while the states of Washington, Idaho and Montana are to the south. Alberta is to the east. On the west, B.C. is bounded by the Pacific Ocean as far north as 50° 40"; between that point and 60°N lies the "panhandle" of Alaska.

The warm Japanese current gives the coastal region of B.C. a very moderate climate. Weather conditions on Vancouver Island and in the heavily populated southwest corner of the mainland are frequently compared with those in England; but the summers are longer, warmer and brighter. The winters are damp, but extremes of temperature are unusual. These conditions have made the region a popular resort area and have also attracted many retired people.

The capital of B.C. is at Victoria on Vancouver Island. The province currently has a population of 2.5 million, growing at an average of 24 percent per decade. British Columbia represents 10.77 percent of the total Canadian population. About 77 percent of the population is urbanized, with 1.1 million living in the Greater Vancouver area. The population is overwhelmingly of British origin. The 1971 census indicated that 58 percent of the population was of British origin.

The province is a significant market for many goods. In 1978, retail sales totaled $8.1 billion (Canadian), which represents 12.03 percent of the total retail sales in Canada and which was 12 percent above the national average. Personal disposable income totaled $18.3 billion (Canadian) in the same year, which was 11.75 percent of the total for

Canada. This translates into a per capita disposable income of $7,220 (Canadian), which was 9 percent above the national average. Real economic growth for the province is forecast at 4-5 percent annually for the foreseeable future.

Industrial Development and Infrastructure

A major influence in the development of the province was the 1915 completion of the Panama Canal, which opened European markets to B.C. products and made Vancouver a major port. The Second World War started spectacular growth in the forest industries, hydro-electric power and manufacturing.

Nearly three quarters of the province is forest covered. There are large mineral-rich areas, and B.C. ranks second only to Quebec in potential water resources. The forest industry has been the backbone of the economy, although mining recently challenged it for supremacy when annual production topped one billion dollars. Most of the production of both industries is exported. Because it depends so heavily on exports, B.C. favors free trade. Export sales exceeded $8 billion in 1978, or 18 percent of the total for Canada. The United Kingdom and European Economic Community each take above 10 percent of B.C. exports, Japan 20 percent and the U.S. over 50 percent. Manufacturing related to forest resources (wood products, pulp and paper) normally accounts for nearly half of all factory employment.

British Columbia ranks fourth among the provinces in total mining production. The volume and value of its products varies considerably from year to year, reflecting the state of world markets and other factors. In 1977, mineral production reached $1.9 billion, representing 10.4 percent of the total for all of Canada. The province is the third largest producer of metals, the most important of which are lead, zinc, copper and molybdenum. Most of the lead, zinc and silver produced in the province comes from the famous Sullivan mine at Kimberly, owned by Cominco Ltd.

Petrochemical Overview

British Columbia has only one petrochemical plant, the 70 million pound per year phenol plant at Ladner. This facility primarily supplies material for the Borden and Reichhold phenolic resin plants which serve the forest products industry within the province. Consideration has been given to upgrading petrochemical raw materials from Alberta in British Columbia to serve Pacific Rim markets, but no firm plans currently exist.

B. Pacific Basin Market

In this report, Japan, Korea, Taiwan, Hong Kong and the ASEAN countries (the Philippines, Singapore, Malaysia, Thailand and Indonesia) were studied. A map showing the locations of these countries is presented as Figure III-B-1. In addition, consideration was given to the import situation in the People's Republic of China.

1. Japan

a. Background

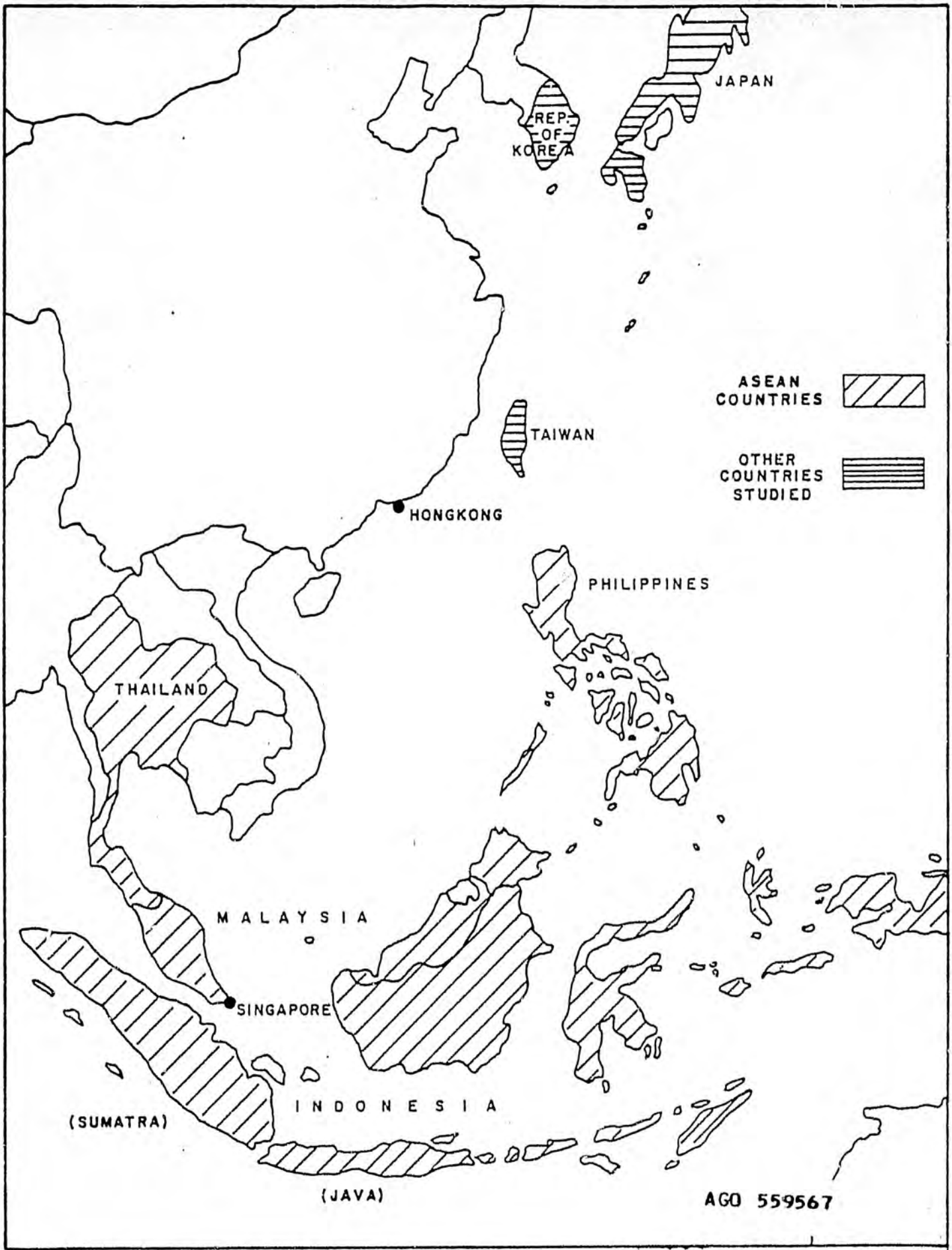
Japan has a land area of approximately 140,000 square miles on four main islands. The country is mostly mountainous, with only about 16 percent of the land area arable. Population was estimated at 113.0 million in 1978, growing at 1.2 percent per year. About 70 percent of this population is urbanized. The very high population density has become a constraint on the overall industrial growth of the country.

The capital and chief commercial center, Tokyo, has a population of 8.7 million. Other principal cities are Osaka (2.8 million), Yokohama (2.6 million) and Nagoya (2.5 million). The total labor force is estimated at nearly 55 million.

Gross national product increased at a compound annual rate of 10.5 percent in real terms during the 10-year period of 1964-1973. In 1974, however, the effects of the OPEC price rises and world recession produced the first GNP decline (1.2 percent) in decades. This was followed by a modest 2.1 percent rise during 1975; the recovery was well under way by the end of 1975, real growth of around 6 percent was achieved during 1976, and moderate growth has continued. Most of the Japanese goverment, industry and public now appear to have accepted that the era of very high growth rates is gone forever, and the government is taking steps to face a new phase of lower growth, which is anticipated to be in the 5 percent per annum range over the period through 1985. The rapid growth of the

FIGURE III-B-1

PACIFIC BASIN COUNTRIES



CHEM SYSTEMS INC.

PROJECT NO. 527 DATE

1960s was based upon transfer of labor into new, fast growing industries, upon imported technology, upon aggressive exporting in a favorable market climate and upon cheap imported energy. Even this new lower level of growth is proving difficult to achieve. The export drive has been highly successful, but the major developed markets of Western Europe and the U.S. are reaching the limits of Japanese penetration in many industries.

Since these existing major markets are reaching their limits, attention is being given to exporting products and complete plants to "third world" markets, particularly in Southeast Asia and the Middle East. Government planning is very consensus-oriented. Public pressure and opinion, with regard to pollution, "quality of life" and similar factors, are a major input to future economic and social planning. This was largely responsible for the Japanese drive to invest in heavy industry and petrochemicals in Southeast Asia, the Middle East and elsewhere, importing products or supplying export markets from these offshore plants as required and thus avoiding further overcrowding and pollution in Japan itself. However, due to slowing growth rates and overcapacity in many industries, including petrochemicals, this trend has been greatly curtailed.

Japan has a unique "lifetime employment system." This system involves extremely high fixed overhead costs to manufacturers because of generous social provisions plus the inability to reduce the labor force in times of reduced demand. Coupled with the traditionally highly leveraged financial structure (only 10-20 percent equity) of Japanese industry, this provides a tremendous incentive to keep operating levels high to cover fixed costs, even if no return on equity capital is generated; hence, the Japanese are determined to achieve high production and export volumes, often at the expense of price levels.

b. Petrochemical Overview

Japan has the second largest refining capacity in the free world, with crude capacity of 5,480,000 barrels per day in 1978. However, the country is forced to import essentially all of its crude since crude

reserves are only 60,000,000 barrels and production is only about 10,000 barrels per day. The country is also deficient in natural gas, with reserves being only 500 billion cubic feet.

The Japanese petrochemical industry grew rapidly during the 1960s and early 1970s to the point where the country is the second largest producer in the world when measured in terms of basic olefins production. The Japanese industry flourished due to the importation of technology from the U.S. and Europe and a favorable feedstock situation based upon low cost crude oil from the Middle East. A substantial home market, plus substantial petrochemical exports, both directly and in the form of manufactured goods, allowed for the erection of world-scale processing units.

The increase in crude oil prices and the recent worldwide recession greatly changed the outlook for the Japanese petrochemical industry from one of extreme optimism to one of considerable pessimism because Japan is now a relatively high cost producer and is facing sharply increased competition in traditional export markets. Ethylene production is a good barometer of petrochemical industry activity. The production levels for the past few years are listed in Table III-B-1. Production fell sharply due to the worldwide recession, and 1978 was the first year in which production exceeded the pre-recession level.

TABLE III-B-1

JAPANESE ETHYLENE PRODUCTION
(Thousand Metric Tons)

1971	3,486
1972	3,816
1973	4,112
1974	4,177
1975	3,358
1976	3,767
1977	3,974
1978	4,387

A list of current Japanese ethylene capacities is shown in Table III-B-2. These capacities tend to reflect the relative size of each firm in the production of large-volume petrochemicals, since petrochemical

complexes in Japan tend to be free standing rather than tied together, as in the U.S. Gulf Coast "spaghetti bowl". After considerable delay, expansions to capacity are being made due to specific company needs for derivative manufacture.

TABLE III-B-2

JAPANESE ETHYLENE PRODUCERS, 1978
(Thousand Metric Tons per Year)

Company	Capacity
Mitsubishi Petrochemical	640
Sumitomo Chemical	570
Mitsubishi Chemical	528
Tonen Petrochemical	501
Maruzen Petrochemical	480
Mitsui Petrochemical	717
Sanyo Petrochemical	390
Idemitsu Petrochemical	362
Nippon Petrochemical	484
Osaka Petrochemical	330
Shindaikyowa Petrochemical	320
Showa Petrochemical	520
Total	5,842

Since there are environmental problems with broad expansion at existing petrochemical sites, much of the expansion at these locations will be of the "scrap and build" approach. In addition, approval has been granted for the development of new petrochemical complex sites on Hokkaido and the northern part of Honshu. This should alleviate, to a degree, the environmental concerns. Full development of these northern sites in the near future is questionable, however, due to business climate concerns. During most of the study period, petrochemical development will occur at or near existing plant locations. Figure III-B-2 is a map showing existing and possible future petrochemical sites in Japan.

While the Japanese petrochemical industry should expand at a rate which is lower than traditional, there has been a re-evaluation of the Japanese producer's role in overseas petrochemical projects. The rapid development of the overseas projects was based on a number of factors which included:

FIGURE I B-2

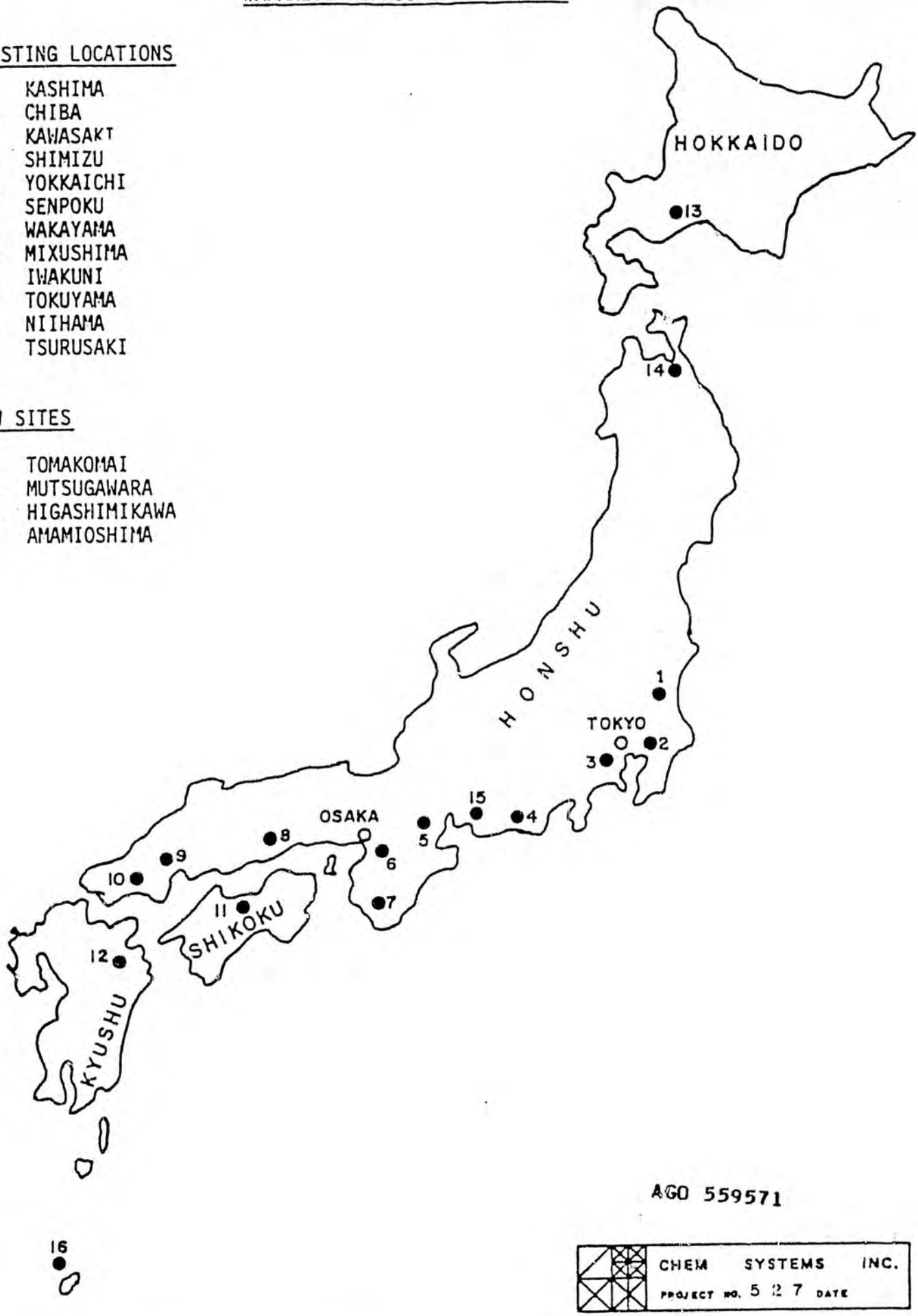
JAPANESE PETROCHEMICAL SITES

EXISTING LOCATIONS

1. KASHIMA
2. CHIBA
3. KAWASAKI
4. SHIMIZU
5. YOKKAICHI
6. SENPOKU
7. WAKAYAMA
8. MIXUSHIMA
9. IWAKUNI
10. TOKUYAMA
11. NIIHAMA
12. TSURUSAKI

NEW SITES

13. TOMAKOMAI
14. MUTSUGAWARA
15. HIGASHIMIKAWA
16. AMAMIOSHIMA



AGO 559571

CHEM SYSTEMS INC.

PROJECT NO. 5 2 7 DATE

- Yen re-evaluation, which reduced the competitiveness of Japanese exports.

- High foreign currency levels and a drive to invest money out of Japan.

- Reaction to pollution problems made it difficult to locate new sites for expansion in Japan.

- The high cost and questionable supply of energy has supported the implementation of petrochemical projects in oil-producing countries.

Since the oil crisis, a re-evaluation of the commitment to overseas projects has occurred, and a number of projects have been dropped. The Mitsui project in Iran, while about 80 percent complete, is just getting restarted after about a year's delay, due to the upheavel in that country. The Sumitomo project in Singapore is proceeding, but at a slow pace. The Mitsubishi group is planning a project in Saudi Arabia, but completion before the late 1980s is not foreseen.

While most of the overseas project development has been by private companies, there is now an effort underway to involve the government in programs to assist the economic development of the less developed countries and secure a dependable oil supply. These projects are taking on a socio-economic overtone, which will necessitate the assistance of the government.

2. Republic of Korea

a. Background

The Republic of Korea (South Korea), with a land area of 37,000 square miles, occupies the southern half of the Korea Peninsula. The whole peninsula is mountainous, particularly the northern and eastern areas.

Good harbors are found only on the western and southern coasts. The largest port and second city is Pusan. Population is approximately 39 million, growing at an average of 2.0 percent per annum. About 55 percent of the population is urbanized, with 6.5 million in the capital, Seoul. The labor force is estimated at 13 million. The population is completely homogeneous, with almost no foreign or minority groups.

Korea is poor in natural resources, densely populated, supports a large military establishment and suffers from shortages of proficient managers and technicians. The great asset of an industrious and able work force, however, has supported rapid industrialization since the early 1960s. GNP rose at over 10 percent per annum through the decade to 1975, based upon exports of light industries such as textiles, clothing, electronics and plywood.

Over the next several years, GNP growth is anticipated to average about 8 percent. However, at present, the country is facing high inflation and economic problems brought about by sharply higher oil and basic commodity costs. This has resulted in trade deficits and lack of hard currency with which to pursue rapid expansion.

Industrial Development and Infrastructure

Korea's past and future growth is based upon added-value processing of imported raw materials for subsequent export. Internal infrastructure is being expanded to sustain this industrial growth.

There is an extensive internal transportation network in Korea. While much is the result of development associated with the military activity of the Korean War, significant additions were made in the past 5-7 years. In 1970, a multi-lane expressway between Seoul and Pusan was completed. By 1980, the government plans to have a total of 1,500 miles of expressway connecting every district in the country. This will support regional development through rapid internal movement of product.

Intercoastal shipping is important for moving products, and the government is embarking on a program of expanding and improving port facilities. Power and water supplies to the industrial areas are geneally adequate.

Government Programs

Korea has a free market economy based upon private ownership of production and distribution. The government maintains some control over the economy through the economic development program, price controls and industrial expansion schemes. Also, the government does own part or all of a number of companies, including the petrochemical and oil industries, which are organized and operated as private entities with independent management. The government has an excellent record of guiding the economy and achieving growth targets.

Korea's Foreign Capital Inducement Law offers liberal tax and related incentives to foreign investment and will favor industries which contribute to balance of payments, introduce advanced technology, utilize domestic resources and increase employment opportunities for Korean labor. Profit remittance is guaranteed by the government.

The government is now becoming more selective, however, regarding the sectors in which it wishes both domestic and foreign investment. Maximum investment incentives will be accorded to the iron and steel, machinery and electronics industries. The large ship building industry will also be supported and developed. Generally, a maximum of 50 percent foreign participation is permitted in new joint ventures.

Regional Associations

South Korea is not a member of any regional association. The proximity of the country to Japan has supported close economic ties between the two countries. Because of the lower labor rate in Korea, Japan utilized Korea as a manufacturing base when labor rates in Japan reduced the competitiveness of Japanese products in world markets.

Japan is the major source of Korean imports and the most important market for Korean exports. The United States ranks second in both categories.

b. Petrochemical Overview

Korea has existing refineries, a fertilizer plant and a petrochemical complex. At present, there are three refineries in operation: Korea Oil Co. (265,000 bbl/day) at Ulsan; Honam Oil Refinery Co. (215,000 bbl/day) at Yeosu; and Kyung In Energy (60,000 bbl/day) at Inchon. In addition, a new refinery and expansions to existing facilities are in progress. The sole olefins complex is Korea Oil's 150,000 metric ton per year ethylene plant at Ulsan. Korea Oil is a 50 percent Gulf Oil, 25 percent government bank, 25 percent Korean public company. This core complex includes a number of downstream facilities, including low density polyethylene, vinyl chloride monomer, acrylonitrile, SBR, alkylbenzene, ethanol, polypropylene, phthalic anhydride and caprolactam manufacture. A second complex at Yeosu is presently nearing completion. This facility will produce 350,000 metric tons per year of ethylene. A third complex had been planned, but the project is being held in abeyance due to present economic situation. However, eventual completion is anticipated. Figure III-B-3 is a map showing the locations of the petrochemical complexes in Korea.

The petrochemical industry is supported by government policies with respect to feedstock pricing and maintenance of product prices for material used domestically at levels such that material destined for export markets can be priced competitively. Unlike countries such as Taiwan, Korea has tended to build up downstream industries before building petrochemical facilities to supply raw material. As a result, most product is used domestically. Korea is replacing Japan as the center for export-oriented labor-intensive industries such as textiles and, as a result, petrochemical consumption is rising rapidly.

FIGURE III-B-3

LOCATION OF KOREAN PETROCHEMICAL COMPLEXES

CHEM SYSTEMS INC.
PROJECT NO. 527 DATE

AGO 559576

3. Taiwan (Republic of China)

a. Background

Although it continues to claim legal soverignty over all of China, the Republic of China exercises control only over the Island of Taiwan, the Penghu Islands (Pescadores) and the "offshore islands" (the two principal island groups are Quemoy and Matsu). Taiwan lies about 90 miles off the southeastern coast of mainland China. It and the Penghu Islands to the west are administered as the Province of Taiwan.

A north-south mountain range forms the backbone of the island. The eastern slope of this range is very steep and craggy, but the western half of the island is generally flat, fertile and well-cultivated. About one-fourth of the island's 13,700 square miles is arable, and some 64 percent of the island may be termed forest land.

Taiwan has a total population of over 16 million, nearly 99 percent of whom live on the Island of Taiwan. The Republic has one of the highest population densities in the world, with about 1200 persons per square mile. The annual population growth rate has averaged 1.9 percent per year until recently, but is declining. The labor force is around 6 million.

The Taiwanese, with the exception of about 225,000 aborigines, are descendants of Chinese who migrated from the coastal mainland areas of Fukien and Kwangtung Provinces during the last 300 years. The two million mainlanders who migrated to Taiwan in 1949 and 1950 come from all parts of China and are referred to as "Overseas Chinese".

Prior to the 1974 worldwide recession, the Taiwanese economy grew rapidly at over 10 percent per annum average, but due to the high export orientation, slowed to under 1 percent real growth in 1974. In 1975, growth was 2.4 percent, but strong recovery occurred in 1976, with about

12 percent real growth. The economic outlook is good, with 6-7 percent per annum growth likely over the next few years, in spite of U.S. recognition of the People's Republic of China.

The government is proceeding with major industrial and infrastructure projects over the next few years (these will cost several billion dollars). The priorities include a major shipyard, a vastly expanded petrochemical production capability, an integrated steel mill complex, port and rail development, completion of the West Coast Freeway, and expansion of power generation facilities.

In general, the economy is highly structured and planned. Extensive use is made of various incentive programs including loans, tax incentives and technical advice to private enterprise. The government has attempted to foster private enterprise by turning over government-owned ventures and not directly competing with private firms. Private industrial production now accounts for nearly 80 percent of the national industrial output versus just over 40 percent in 1952. Since that time, the structure of industry has also changed significantly, with heavy industry now accounting for about 50 percent of output (versus 30 percent in 1960).

The petroleum and chemical industries represent a major sector of Taiwan's economy. The growth of industry made it feasible to establish a petrochemical industry in the early 1960s. Taiwan is supplying many raw and intermediate materials for its important plastic, synthetic fiber and synthetic rubber industries, and the range of its petrochemical products is constantly being expanded.

Taiwan has an unusual complement of supporting industries for a developing country. Its substantial machine tool industry supplies machinery of conventional and special design at prices which are 50 percent or less than equivalent European or United States machine prices.

Taiwan has well-developed highway and rail systems. These are concentrated along the West Coast, connecting the northern and southern ports of Keelung and Kaohsiung and the three major cities of Taipei, Taichung and Kaohsiung.

AGO 559578

Taiwan's major ports are in Kaohsiung and Keelung. Although both ports are currently handling containers, Kaohsiung, with much more space in which to expand, will have the country's greatest capacity to handle and store containers in the future. In addition, a new port is under construction at Taichung for the purpose of handling the rapid increase in industrial growth already taking place around the Taichung Export Processing Zone.

In an effort to make Taiwan particularly attractive to export-oriented manufacturing investors, the government embarked in the early 1960s on a vigorous program to develop strategically located Export Processing Zones. Enterprises located in these zones receive the favorable tax treatment provided by the Statute for Encouragement of Investment.

Power and water supplies are constantly being expanded and will not be a constraint to growth.

Government Programs

The government recognizes that continued foreign and domestic investment is essential to sustained economic growth in Taiwan. There is little interference with most of the activities of the private sector, although there is government ownership in certain industries such as petroleum refining. Foreign investment is welcome and is not discriminated against, though the future emphasis will be upon high-technology and capital-intensive industries, rather than on the labor-intensive industries which have been allocated for most investment in the past. Although joint ventures are frequent, local participation is not required by law or policy.

Incentives are provided for investment in a wide range of industries, with special attention currently being given to petrochemicals, metal, machinery, glass and man-made fibers.

The government has a successful history of economic development planning. The plans are indicative in nature, leaving the private sector with much of the responsibility for achieving the targets. However, they set forth a wide range of policy measures to improve the industrial environment so that the targets can be met. In addition to economic plans, the government is also formulating separate long-range plans for transportation, electric power and manpower development.

Taiwan's tariff rates range from free to 120 percent ad valorem. The following is a general breakdown of duty rates:

Tariff Duty	Applies to (generally)
0 - 20%	Essential raw materials, machinery and fuels
35 - 80%	Most manufactured articles
80%+	Most luxuries

In no case are preferential rates granted. There are also some non-tariff import controls, which may be restrictive in certain cases.

The government endorses free trade as an ultimate objective, but does practice protectionism at present. This policy is regarded as necessary to stimulate industrial development and balance international payments.

Regional Association

Taiwan is not a member of any regional association and has only limited bilateral trade agreements with other countries.

b. Petrochemical Overview

Taiwan's hydrocarbon industry is controlled by the Government-owned Chinese Petroleum Corporation. Refining capacity is 425,000 barrels per day. Essentially all of the country's crude is imported, but there are gas reserves of 700 billion cubic feet and condensate reserves of about 12,000,000 barrels.

The petrochemical industry in Taiwan is important to that country's economy as it supplies the bulk of the raw material requirements for its synthetic fiber and plastics fabrication industries, plus material for export. The largest single industrial enterprise in Taiwan (Formosa Plastics Group) is based primarily on the production of plastics and synthetic fibers. In terms of value added, the petrochemical industry in Taiwan accounts for nearly 10 percent of the total value added by all manufacturing industries.

The petrochemical industry in Taiwan is owned by both the public and private sectors. In general, the public sector concentrates on production of basic petrochemicals (e.g., olefins and aromatics) while the private sector concentrates on intermediates and final products (e.g., vinyl chloride monomer and polyvinyl chloride resins). In recent years, production of petrochemical products in Taiwan has risen at rapid rates and there are plans for continued significant expansions. Although some petrochemicals are exported directly, the Taiwanese petrochemical industry is very dependent upon the indirect export of petrochemicals as fabricated products, plastics and synthetic fibers.

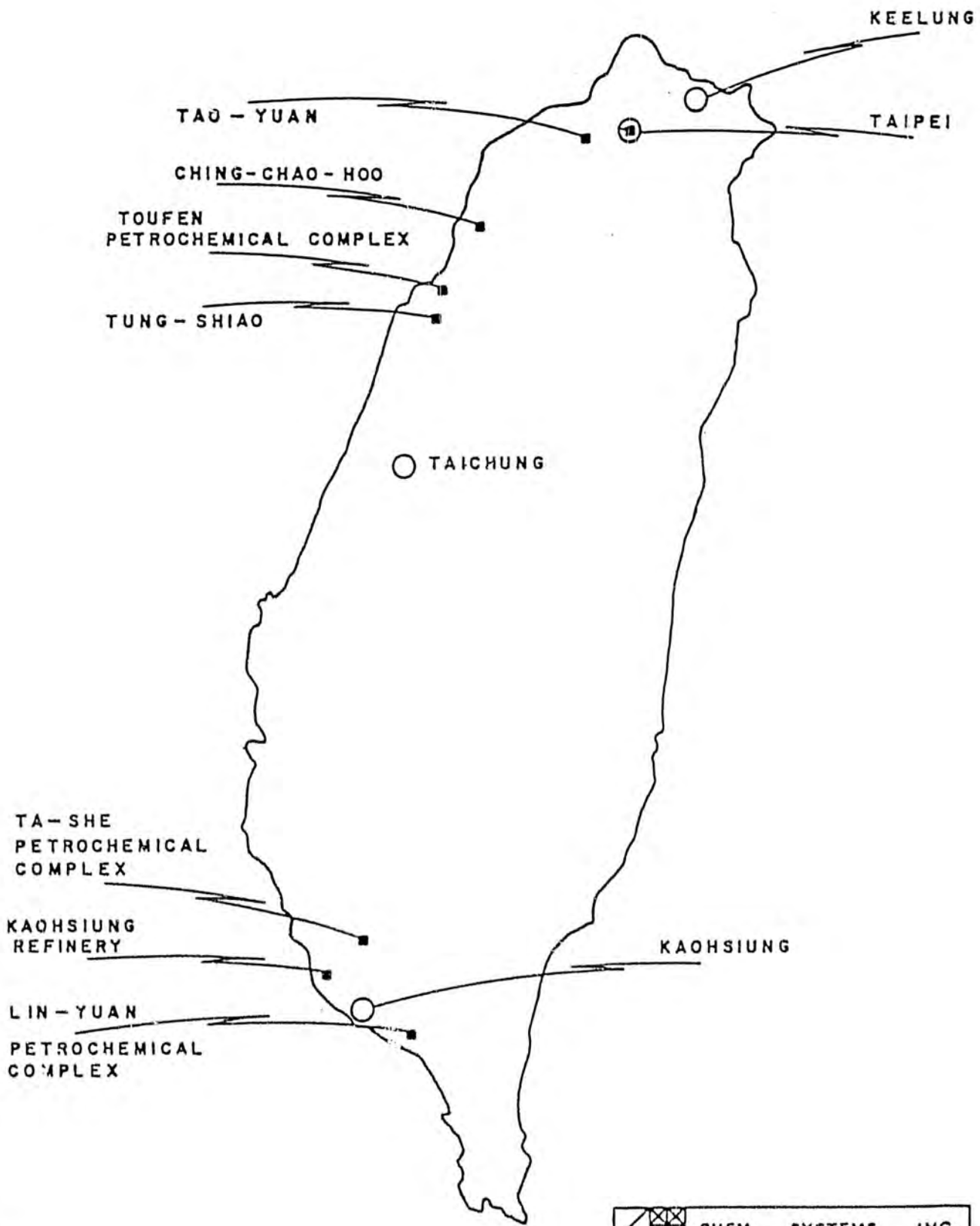
The Taiwanese petrochemical industry is based upon the basic petrochemicals supplied by the Chinese Petroleum Corp. Ethylene is produced in a 55,000 metric ton per year ethane cracker, a naphtha cracker of similar size and two 230,000 metric ton per year naphtha crackers.

In addition, Chinese Petroleum has just approved erection of a new olefin plant which would increase ethylene capacity by 350,000 metric tons per year. These basic petrochemicals are used in the production of a wide range of derivatives, including low and high density polyethylene, polypropylene, vinyl chloride, styrene, SBR elastomer, dimethyl terephthalate, caprolactam and acrylonitrile. A number of other units are under construction.

A map showing the major petrochemical sites in Taiwan is presented as Figure III-B-4.

FIGURE III - B - 4

TAIWAN



CHEM SYSTEMS INC.
PROJECT NO. 527 DATE

AGO 559582

4. Hong Kong

a. Background

Hong Kong is a British crown colony located off the Kwangtung coast of southern China, comprising the island of Hong Kong and adjacent islets, Kowloon peninsula and the leased New Territories on the mainland with surrounding islands. Hong Kong Island takes up only 28 square miles of the total 380 square mile area of the Colony.

Population is estimated to be over 5 million, nearly 99 percent of which is Chinese. The balance is mainly British. Due to its almost total dependence upon exports, the Hong Kong economy came to an abrupt halt in 1974 and 1975, with real GNP growth of 4 percent and 3 percent, respectively. After the double-digit growth of the previous decade, this was a serious reversal. Recovery began during 1975, however, and 1976 was a boom year with a 50 percent export increase and well over 10 percent real GNP growth. Confidence in Hong Kong's economic future remains high, and medium-term real growth rates of at least 5-6 percent per annum may be expected, provided the major Hong Kong markets of the United States and Western Europe avoid serious recessions.

Industrial Development and Infrastructure

Industry was introduced to Hong Kong on a small scale in the early 1930s under the stimulus of the Commonwealth Preference System. During that period and through the 1940s, Hong Kong's main role was as an entrepot, a center of trade and trans-shipment between China and the rest of the world. This activity was responsible for the development of excellent facilities for banking, shipping, warehousing and insurance.

The most significant changes in Hong Kong occurred in 1949 and 1950, and the events that took place were largely responsible for the industrial development which resulted. In 1949, the government of China changed and

over 1 million immigrants came to Hong Kong from Communist China. In 1950, the Korean War resulted in a United Nations embargo on trade with China. This severely reduced Hong Kong's entrepot trade, and it became necessary to quickly find an alternative source of income to survive.

This led to Hong Kong's industrial revolution. Local business people and the immigrants, who brought machinery, technical knowledge and capital, took advantage of a large pool of skilled and semi-skilled workers to establish a manufacturing base. Hong Kong has virtually no natural resources and depends for its survival upon the energy, skill and intelligence of its people, its deepwater harbor and its strategic geographical position.

Textiles was Hong Kong's first major industry, and it was based mainly on cotton. In the late 1960s, synthetics became significant. Even with the development of other industries, textiles and clothing in 1976 accounted for 56 percent of exports in dollar value. The second largest export industry is electronics, with plastic products (principally toys, dolls and flowers) the third most important business category.

As far as Hong Kong's future is concerned, changes are taking place within the Southeast Asia region which are shaping its long range structure. The developing nations, including South Korea, Taiwan, Thailand, Malaysia, etc., are emulating Hong Kong by developing textile and plastics operations of their own. They are able to compete with Hong Kong on the basis of lower cost labor. As a result, Hong Kong business has concluded that it is to its advantage to retain manufacturing facilities requiring more sophisticated techniques. Hong Kong's manufacturing base will thus be oriented more strongly to more sophisticated products with a higher unit value, made from combinations of materials requiring more complex assembly and processing.

There has been some speculation about the fact that the United Kingdom's lease on Hong Kong expires in 1998 and that the People's Republic of China (PRC) might not renew it, thus clouding Hong Kong's future. This is not considered a signficant factor for a number of reasons:

- The PRC has never really recognized any agreements made by Nationalist China and could have taken it over any time it chose to.

- The U.K. does not dispute PRC's claim that Hong Kong is Chinese.

- Hong Kong serves a very useful purpose to the PRC. Over 50 percent of Hong Kong's food is obtained from the PRC and almost 20 percent of its total imports are from that source. Aside from its value as a source of foreign exchange, Hong Kong serves the PRC by providing an excellent channel for the flow of goods into and out of the country without any "cultural pollution".

It is anticipated that this relationship will continue to exist for the foreseeable future.

Government Programs

The Hong Kong government maintains a classic laissez-faire posture towards economic activity in the Colony. There is a minimum of regulation, and taxation of personal and corporate income is limited to 15 percent. The government also adheres to a philosophy of free trade. Duties are levied on tobacco, alcoholic beverages and automotive fuels for revenue purposes only. Most imports and exports are subject to a trade declaration charge at a nominal rate. Import and export licensing is kept to the minimum required for the fulfillment of the U.K.'s and Hong Kong's international obligations, monitoring of essential commodities and the protection of health and safety. Hong Kong has a constant trade deficit due to its dependence upon imports for all raw materials. This deficit is compensated for through the Colony's considerable invisible earnings (particularly from tourism and commerce) and a sizeable annual inflow of capital.

Regional Associations

Hong Kong is a free trade area with no association or commitments to other countries in the region.

b. Petrochemical Overview

There is no oil or gas production nor any refining industry in Hong Kong.

At present, Dow's polystyrene plant is the only petrochemical venture in Hong Kong. No additional facilities are planned, nor are any likely in the foreseeable future. A map showing the location of Dow's facility is presented as Figure III-B-5.

5. Philippines

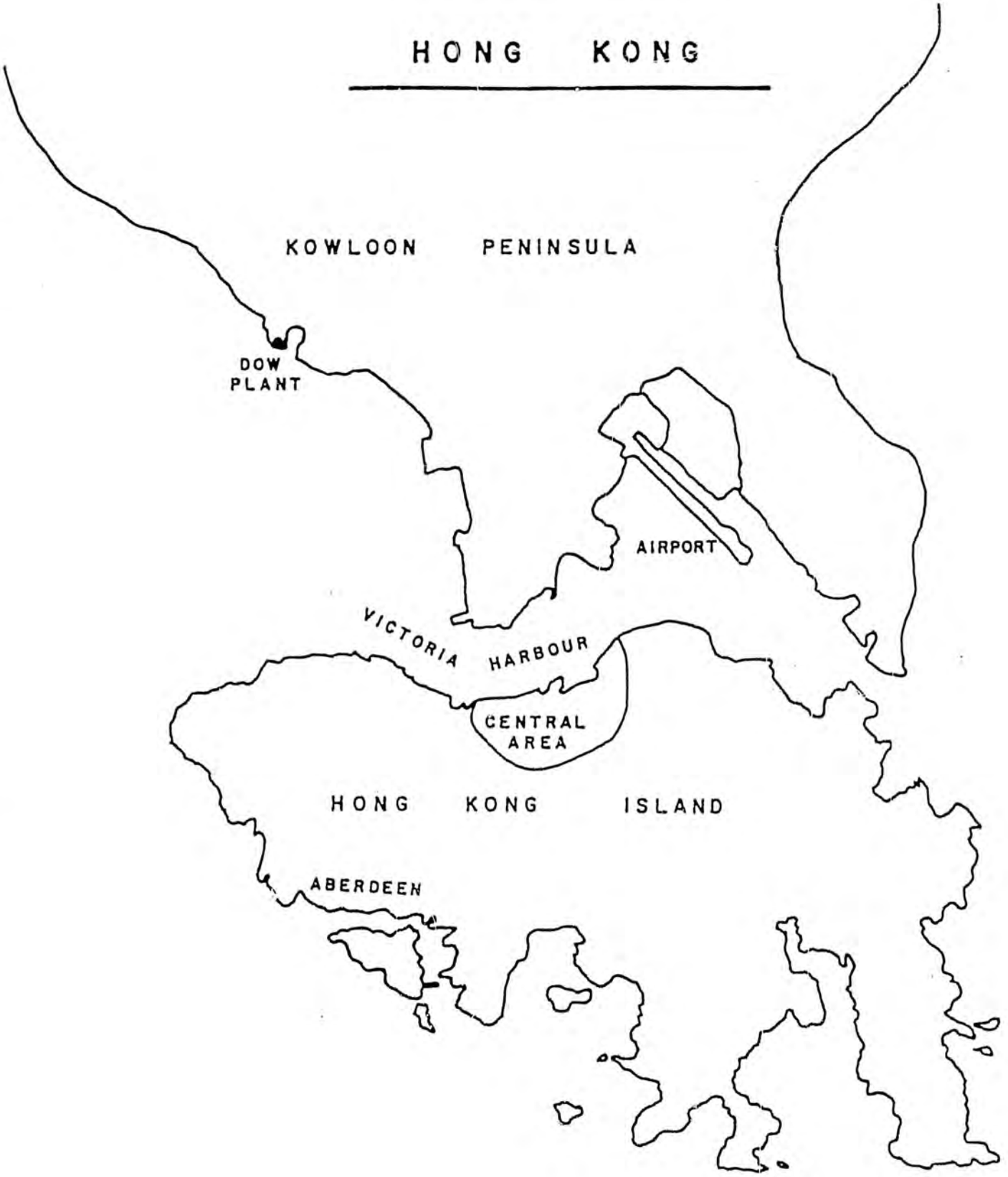
a. Background

The Philippines is an archipelago country of over 7,000 islands with a total land area of almost 114,000 square miles. Of this area, about 41 percent is cultivated, 40 percent is forested and the balance is unusable mountainous country. The principle economic and population center is the greater Manila area, where there are 4 to 5 million people. The total population is about 44 million, growing at 3 percent per annum. Efforts at planned population control have had very limited success. The labor force is around 14 million. A map of the Philippines is shown in Figure III-B-6.

Although large areas of the country are very fertile, the country is in the middle of the Pacific typhoon belt and natural disasters can have major effects upon food production. The government is investing large sums in flood control dams, properly laid out irrigation systems and the removal of illegally built fish ponds, which impede the progress of flood water. The development of a viable agricultural sector is essential so that the government can reduce expenditures of foreign exchange for

FIGURE III - B - 5

HONG KONG

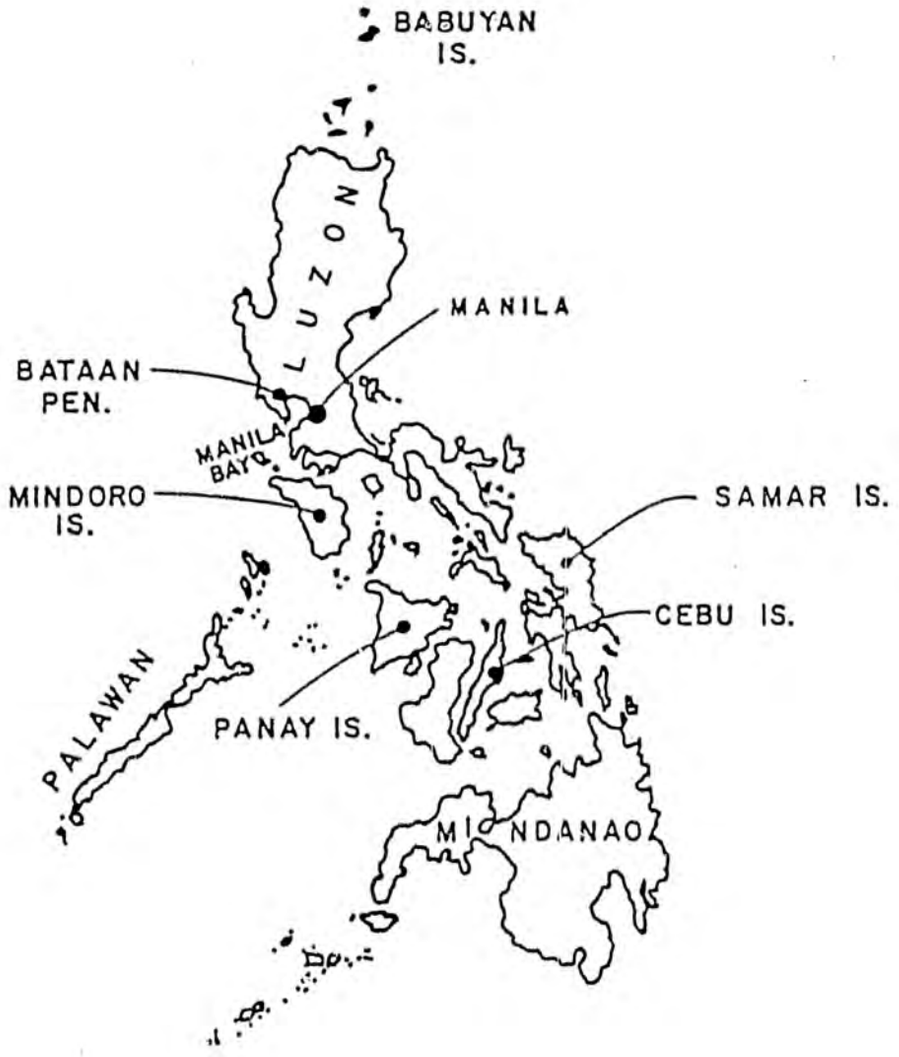


AGD 559587

CHEM SYSTEMS INC.
PROJECT NO. 527 DATE

FIGURE III-B-6

PHILIPPINES



AGO 559588

CHEM SYSTEMS INC.
PROJECT NO. 527 DATE

food. In addition, some of the Philippines' principal foreign exchange earners are agricultural products, including coconut products, sugar and timber.

The islands are also well endowed with minerals. The Philippines is the world's sixth largest producer of copper, and exploration activity for petroleum is now becoming an important activity. Some discoveries have already been made.

GNP growth was around 6 percent per annum in 1975 and 1976. Balance of payments problems are restricting long-term growth prospects, with only a 4-5 percent per annum growth anticipated.

Industrial Development and Infrastructure

The economy of the Philippines is still basically underdeveloped and agricultural. Industrial production has steadily expanded and diversified, but its growth has been relatively slow in recent years. The Government has now established a set of policies geared to the creation of a climate conducive to industrial growth, and prospects for continued industrial growth over the next years are good.

The government's industrial strategy places special emphasis on the processing of local raw materials, the growth of manufactured exports, employment generation, and regional dispersement and development of small and medium scale industries.

The government is spending large sums on road construction and rural electrification. There is a substantial program for rehabilitation of railroads, which are fairly well developed on Luzon and Panay Islands with about 750 miles of track. The total length of roads is nearly 40,000 miles. The Pan-Philippine highway, which is to span the length of the country from north to south, is more than 50 percent complete, and many feeder roads are being built to rural areas which will open new areas for markets and industry.

For many years, the electric generating capacity in the Philippines did not keep pace with the rest of the economy and blackouts are still commonplace. There is now a firm program developed for rural electrification and a number of fairly large-scale projects for hydro, geothermal, nuclear and coal power plants to supplement imported fuel oil. These facilities should be able to support the many new industries that the Bureau of Investment (BOI) is trying to attract into the country.

To relieve the port congestion problem, there is a large expansion under way in Manila which includes facilities for full container ships. In addition, there are plans to build a complete new deep-water port at Batanyas, south of Manila, where two of the country's oil refineries are located. Also under way are projects to increase the port facilities at Cebu City, which is the principal port and distribution center for the Visayas or central part of the country.

On Mindanao in the south, the port at Illigan is also being expanded, as this is the location of the integrated steel works, ferro-chemicals and the new investment by Kawasaki Steel of Japan in a sintering plant.

Government Programs

Due to its long association with the United States, the Philippines was once very much private enterprise-oriented. Since the advent of martial law in September 1972, however, the government has adopted a much more active role in the economy. The state is now involved in fertilizer production, all aspects of the petroleum industry and utilities. Also, the government has used the Bureau of Investment (BOI) as a vehicle to promote industrial development plans.

There is a wide range of incentives for new companies registered with and given BOI approval. These include tax relief, accelerated depreciation, tax-loss carry-forward, tax credits for import duties on machinery and equipment, the right to use expatriate management, protection from competitive imports, etc.

Basically, the BOI tries to promote "pioneer" industries. These are industries which do not exist in the country at present and which have local and/or export market potential. These would include many activities in the petrochemical and plastics fields.

Tariff protection is given where necessary to support local industries. In general, raw materials imported for processing and subsequent re-export are eligible for refund of tariffs when the finished products are exported. Current duties on basic petrochemical imports are in the 10 to 30 percent range.

Regional Associations

The Philippines is a member of ASEAN and, in common with the other members, has made nominal efforts towards regional cooperation. Early in 1977, tariff reductions between the Philippines and Singapore were agreed upon. In the long term, the Philippines could become a leading promoter of regional cooperation in ASEAN.

b. Petrochemical Overview

At present, there is only limited petrochemical production in the Philippines and petrochemical consumption is quite low. A major complex was planned by Herdis at Limay on the Bataan Peninsula with a government-owned core complex and with major participation by foreign companies in the downstream operations. The output from the facilities would have been sold locally and exported primarily to other ASEAN countries. This project has been changed and significantly reduced in scope. At present, a 90,000 metric ton per year low density polyethylene plant (with USI-Far East participation) and a 50,000 metric ton per year polypropylene plant (with Hercules participation) are planned. Both of these facilities would utilize imported feedstocks and primarily serve the local market.

6. Singapore

a. Background

Singapore is situated at the southern tip of the Malay Peninsula, with one main island and over 50 smaller islets comprising a total of 220 square miles. Major land reclamation schemes continue.

Just under 20 percent of the land area is cultivated, but food imports remain significant. Urban development covers over 35 percent of the total land area and continues to expand. Population is currently 2.3 million, growing at around 1.5 percent per annum. Zero population growth is the government objective, but this is proving difficult to achieve. About 75 percent of the population is Chinese, 15 percent Malays, 7 percent Indian and Pakistani and 3 percent European and others. The labor force is around 850,000. Singapore came through the 1974-1975 worldwide recession relatively well. Real GNP increased by 6.0 percent in 1974, 5.7 percent in 1975 and around 7 percent in 1976. This current growth is relatively poor compared to the 12-13 percent per annum rates achieved prior to 1973, and readjustment to this more modest growth has been slow to develop. Key factors responsible for double digit growth in the early 1970s are probably changed forever. Highly competitive labor-intensive production has been undermined by rapid labor cost increases; imported energy will no longer be cheap; the Southeast Asian oil boom, with Singapore as the regional headquarters, has collapsed - at least temporarily; and finally, the economy is now relatively mature, making rapid growth increasingly difficult. In the short/medium term, worldwide overcapacity and reduced demand expectations have badly hit the important oil refinery and shipbuilding industries. Shortage of suitable land will be a long-term constraint on major industrial development.

Projections are now for 7-8 percent per annum growth of the economy, to continue through the early 1980s. Singapore is generally regarded as

having a highly efficient, well-run economy and is likely to become the financial, industrial and services center for the ASEAN region.

Industrial Development and Infrastructure

Since its separation from Malaysia in 1965, Singapore has made maximum effort to attract and develop export-oriented industries. This campaign has been highly successful, and it prevented major disruption of the economy in 1971, when the British forces withdrew from their Singapore bases, which had previously contributed 20 percent of the gross domestic product and employed over 40,000 people.

Government bodies provided infrastructure, sites and buildings for new industries. There is a relatively skilled and experienced work force and constant efforts by the government to upgrade skills and training at all levels. Extensive investment incentive programs have been implemented. Most new companies and industries have been successful, and Singapore is now firmly established as the industrial center of the ASEAN region. The port of Singapore is one of the world's largest and the communications network is good.

The only real long-term infrastructure problem stems from the lack of available land for continued development. Although the government has become more selective regarding the type of industry to be encouraged in Singapore, petrochemicals has been selected as a favored industry for development.

Government Programs

Singapore was a pioneer in developing an organized program of incentives for attracting new industries. These include all forms of tax exemptions and accelerated depreciation provisions, plus complete freedom in remittance of foreign exchange. Singapore is basically a free port, with no tariffs or duties on most raw materials and fabricated products. Protective tariffs are imposed where necessary to support new local industries, and this would probably apply to any new petrochemical and plastics production.

The government is closely involved in industry, but the objective has been to assist and promote rather than to regulate. It has invested both on a wholly-owned and a joint venture basis in most basic industries, and government equity involvement in all petrochemical ventures is likely.

Regional Associations

Singapore is a member of ASEAN; it differs, however, from all other members of the group in being a producer of finished products rather than of raw materials.

As the fourth largest port in the world, Singapore trades and trans-ships a great deal of commerce for its ASEAN neighbors. Despite development of port and export facilities in other ASEAN countries, Singapore will undoubtedly remain the dominant port and trading center for the region.

The ASEAN group is still a very loose association. No common tariff policy has yet been promulgated. In the long term, attempts to divide up projects and industries between the member states will probably succeed. At present, however, each state tends to develop its own plans and projects. This is particularly true of Singapore, and the promotion of its petrochemical project has upset its ASEAN partners due to the lack of consultation and consensus. Since Singapore has so much to gain from the development of a strong, cohesive ASEAN group, with Singapore as the trading and manufacturing center, it is to be expected that strong long-term support will be given by Singapore to joint economic and industrial policies.

b. Petrochemical Overview

At the present time, Singapore's involvement in petrochemicals is limited to a 15,000 metric ton per year polyvinyl chloride plant based upon imported monomer and various resin converters. The imports of resins are largely for the converting industry, which, in turn, exports the bulk of its products.

Singapore has no oil or gas reserves. However, with 918,000 barrels per day of crude oil refining capacity in existence, Singapore has the potential to produce adequate naphtha for a world-scale ethylene facility. At the present time, the majority of this naptha is exported - to Japan, Taiwan, the United States and Europe. A map of Singapore is presented as Figure III-B-7.

The Economic Development Board had been studying the feasibility of an integrated petrochemical project for many years and had developed a proposed joint-venture between Sumitomo and the Development Bank of Singapore. With the lessening of petrochemical growth rates, brought about by rising crude oil prices, Sumitomo delayed with proceeding. Since then, however, the Singapore project was made a Japanese national project with the involvement of over 20 firms which would take over part of Sumitomo's interest. Site preparation for the complex has been completed, but implementation continues to be slow.

The cracker will have a capacity of 300,000 metric tons per year of ethylene, and low density polyethylene, high density polyethylene, ethylene oxide/glycol and polypropylene facilities will be built to utilize the output of the core complex.

7. Malaysia

a. Background

The Federation of Malaysia has a total area of 125,780 square miles, of which Peninsular or West Malaysia takes up 51,450 square miles. The East Malaysian States of Sabah and Sarawak take up 28,880 and 46,740 square miles, respectively. A map of Malaysia is presented as Figure III-B-8.

The population, which is estimated at about 12.5 million and is increasing at a rate of about 3 percent per annum, is concentrated mainly along the lowlands of the western side of the peninsula. The large land areas east of the mountains on the peninsula and the two East Malaysian states are sparsely populated.

FIGURE III-B-7

SINGAPORE

AGID 559596

CHEM SYSTEMS INC.
PROJECT NO. 527 DATE

FIGURE III-B-8

MALAYSIA

AGO 559597

67

CHEM SYSTEMS INC.
PROJECT NO. 527 DATE

The racial make-up of Malaysia is roughly 50 percent Malay, 35 percent Chinese and 15 percent Indian, Pakistani and others. There has been friction in the past between the Chinese and the Malays because the Chinese dominate the commercial sector of the economy.

There have been substantial efforts at upgrading and projecting the racial Malays into the industrial and commercial sectors of the economy. This is succeeding to some extent as educational facilities are made available to a greater portion of the population. The labor force is around 4.4 million, with unemployment about 7 percent.

The more developed areas on the western side of the peninsula provide the main agricultural products, including rubber, palm oil, pineapples and food crops such as rice. The tin mines, which have been the source of much of Malaysia's wealth in the past, are also located mainly on the western side of the peninsula. With the population concentration and center on the western side, this area has also been the principal area of industrialization.

The oil and gas discoveries have largely been off-shore Sabah, Sarawak and the east coast states of Pinang and Trengannu. In the future, as oil and gas production reach commercial operation, it is likely that new industrial centers, based on petroleum and petrochemicals, will be located on the east coast of the peninsula and possibly in the East Malaysian states.

The economy survived the 1974-1975 recession fairly well. Recovery was largely due to improved export markets for rubber, tin and other commodities which form the mainstay of the economy. Over the next few years, growth is anticipated to average about 5-6 percent per annum. Manufacturing industry accounted for 11.9 percent of GNP in 1971, 17 percent in 1975 and is projected in the 20-year Perspective Plan to reach 35 percent by 1990.

Industrial Development and Infrastructure

The government is making efforts to improve land communications and develop the underpopulated areas. The East-West highway crossing the northern part of the peninsula provides access to large agricultural and timber areas. There has also been investment in the modernization and expansion of railroads. In East Malaysia, the road system has been gradually improved. However, much of these vast areas is remote and accessible only by air or river travel.

Most of the industrial development has occurred around the major population centers. The largest area is the 30 mile strip between the capital of Kuala Lumpur and the principal port, Port Klang. This area is rapidly filling in with planned industrial sites, which comprise electronic and textile industries for export and other import substitution industries. Other industrial sites are located on the outskirts of principal towns, including Johore Bahru in the south and Malacca, Ipoh and Penang in the north.

There are about 100,000 miles of roads in peninsular Malaysia, but only about 1,000 in Sarawak and less than 2,000 in Sabah. There are 1,200 miles of railways in the peninsula; these connect with Singapore in the south and Thailand in the north. Now that the new East-West highway is completed across the north of the peninsula, all the habitable areas have good access to the manufacturing and trading centers and ports. This allows manufacturers to move farther afield to tap sources of low-cost labor and at the same time allows more trade to develop in the rural areas. As income for manufacturing increases, it will help to smooth out the sharp peaks and dips in the Malaysian GNP which have occurred in the past due to reliance on export prices of commodities.

The National Electricity Board supplies most of the power to the country. About two-thirds of the 1,200 MW capacity is thermal and one-third is hydropower. There are other large new hydro projects under construction, and nuclear power is being considered as an alternative to

oil in the future. The NEB has been able to keep up with demand thus far and seems to be capable of meeting future requirements. Water is generally handled by the individual states and has not been a problem for developing industries.

When large new facilities are planned for the east coast of the peninsula to utilize the off-shore hydrocarbons, considerable preplanning and infrastructural development will be required.

Government Programs

The Malaysian government has well-developed agencies and programs to plan and assist in the development of the country. Statutory bodies will participate in joint ventures with foreign companies, and MIDF (Malaysian Industrial Development Finance) will assist in medium- and long-term loans.

The prime objective of the above organizations is to assist the indigenous racial Malays to penetrate the commercial and industrial sectors of the economy. Since the Malays generally do not have the equity capital required to participate in various proposed joint ventures, there may in the future be a trend whereby the government in one form or another may take up equity in new manufacturing enterprises in order to ensure that a majority of the venture is available to Malays.

The government has taken steps to become more directly involved in commodity trading, including successful price stabilization schemes for the important rubber industry.

Petronas, the national petroleum company, was created in 1974 and is responsible for anything to do with the petroleum industry, from exploration to the final consumer and including products such as petrochemicals and fertilizers. Agreements are gradually being renegotiated between Petronas and the foreign oil companies, and production and exploration have restarted after the nationalization scares.

The government agency for assisting a potential new investor in Malaysia is the Federal Industrial Development Authority (FIDA). Since the creation of Petronas in October 1974, FIDA no longer has the authority over activities involving the petroleum or petroleum-derived chemical industry, as this responsibility now belongs to Petronas. Petronas will develop its own guidelines and incentives for potential investors in the petroleum-related industries.

The incentives FIDA offers other manufacturers are numerous. They include:

- Pioneer status, which grants an approved company exemption from income and development taxes for a period of 5 years.
- Investment tax credits are granted if the proposed industry will produce a "priority product", locate in a "development area" and utilize 50 percent or more of local raw materials.
- Export-oriented industries which export 90 percent or more of their production have extended tax holidays.
- Imported machinery and raw materials are exempt from duty, and additional export allowances are made for local content products.
- Deserving industries are given anti-dumping tariff protection.
- There is a bilateral Foreign Investment Guarantee agreement with the United States.
- Investors are freely permitted to remit capital and income from investments in Malaysia.
- Tariff protection is granted to a wide range of manufactured items.

It is the government's declared policy that tariff protection should be used as a tool to encourage local industries. Where protection from foreign dumping is required, each case is decided on its own merits, with efficiency and cost of production of the local item the main criterion.

Regional Associations

Malaysia is a member of ASEAN, and its balance of payments is very much governed by its exports of primary commodities: rubber, tin, palm oil, timber and, increasingly, oil and gas. Malaysia has been very vocal in pushing for regional producers of these commodities to act in a concerted effort to maintain levels.

As far as intra-ASEAN trade is concerned, Malaysia has not been active in promoting complementary industries or trade. The prime emphasis has been upon developing industries beneficial to Malaysia, without any great enthusiasm for joint ASEAN objectives.

Malaysia has 140,000 barrels per day of refining capacity in contrast to crude oil production of 160,000 barrels per day in 1978 and reserves estimated at 2.8 billion barrels. In addition, there are gas reserves estimated at 17 trillion cubic feet.

b. Petrochemical Overview

Malaysia's petrochemical industry can technically be said to date from 1967, when a 50,000 metric ton per year refinery hydrogen-based ammonia plant was built adjacent to the Esso refinery at Port Dickson. Effective October 1974, all future development was put in the hands of Petronas, the national petroleum company, as part of the law establishing the company as the Malaysian vehicle for controlling all activities in the petroleum and petroleum-derived industries. Although the principal interest has been to develop crude oil production, it is believed that there are substantial gas reserves off-shore Sabah, the other East Malaysian State.

At one time, it was assumed that a State Development Corporation would set up a 250,000 metric ton per year ethylene cracker. This project has never passed beyond the conceptual stage and is very unlikely to be built.

8. Thailand

a. Background

Thailand has an area of 195,000 square miles, of which nearly 40 percent is cultivated and another 55 percent is forested. The economy is mainly agricultural: agriculture employs over 75 percent of the population and produces nearly 30 percent of GDP and the dominant proportion of export revenue.

The population is about 43 million, increasing at 3 percent per annum. The population is mainly Thai, but there is also a 15 percent Chinese minority. The work force is estimated at 19 million, mostly outside the cash economy and involved in agriculture. Most industrial activity is in the Bangkok area, with its population of 4 million.

The Thai economy was not severely affected by the worldwide slump of 1974-1975, since its basically agricultural exports continued to be in demand. Real GNP has increased at about 6 percent per year since then, and over the next few years, GNP growth of around 5-6 percent is anticipated.

Thailand's international credit rating is excellent, based upon good economic conditions. However, the political climate is still a concern because of the threat of aggression by the Communists and actions by the Moslems in the south.

Industrial Development and Infrastructure

Thailand may be divided into the Greater Bangkok region and "up-country". The port of Bangkok, 30 miles up the Chao Phraya River, handles 90 percent of Thailand imports and 75 percent of its

exports. Congestion is a major problem and maximum vessel size is 10,000 DWT. Plans have been discussed for a new commercial port on the Gulf of Thailand at Sattahip, currently a military base. Development is in the future, however. There are two oil refineries located on the coast and the site allocated for the formerly planned petrochemical project is nearby. A map of Thailand is presented in Figure III-B-9.

The road network is fairly well developed, including 12,000 miles of national highways. There are nearly 2,500 miles of single-track railways, and the rivers are also used extensively for inland transportation.

Government Programs

In addition to owning the utilities, transport systems and communications, the Thai government has been heavily involved in manufacturing operations. There appears to be little enthusiasm for government joint ventures with foreign companies.

The government has taken steps to improve the investment climate after the recent political and labor troubles, and business confidence is likely to improve. There are no requirements concerning Thai ownership of any project. The economy is basically a free one.

The Thai Board of Investment appears to be a well-organized body whose role is to assist foreign investors interested in coming into Thailand. They claim their incentives are more attractive than those of other Southeast Asian countries. Their investment incentives cover all the standard points such as tax holiday, full remittance of foreign capital invested, royalties, interest on foreign loans, and guarantees against nationalization and competition from new state enterprises.

Tariff protection, subject to justification of needs, can include import bans on competitive products or the raising of import duties on foreign competitive products. If the project is export-oriented, there is exemption from import duties and business tax on raw materials and re-export items; exemption from business tax for domestic raw materials;

FIGURE III-B-9

THAILAND

AGO 559605

CHEM SYSTEMS INC.
PROJECT NO. 527 DATE

and exemption from duty and/or business tax for all imported and locally produced machinery and equipment. Imports duties on most petrochemicals are currently in the 10 to 30 percent range.

Regional Associations

Thailand belongs to ASEAN, and Bangkok is the seat of the UN Economic and Social Commission for Asia and the Pacific (ESCAP), SEATO and other regional organizations. As in the other ASEAN countries, there has been a lot of planning and conversation on regional cooperation for industrialization. In the case of petrochemical development, Thailand has operated on the principle that an adequate inland market exists for economically viable plants for most of the basic petrochemicals. However, no developments in this area are likely for several years. Thailand is evaluating the feasibility of a $200 million soda ash project proposed by ASEAN to meet regional requirements. This would utilize high purity rock salt found in northeastern Thailand.

b. Petrochemical Overview

Thailand has 160,000 barrels per day of refining capacity. At present, the country has small oil reserves, estimated at 270,000 barrels, but has substantial gas reserves, estimated at 5 trillion cubic feet.

Major petrochemical complexes had been planned for Thailand in the early 1970s, but they died as a result of the oil crisis. At present, activities are primarily limited to polystyrene, PVC and fiber production. At present, a 90,000 metric ton per year low density polyethylene plant and a 50,000 metric ton per year high density polyethylene plant are planned, based upon imported ethylene. In addition, Exxon is reportedly evaluating a natural gas liquids based complex, which would ultimately provide feedstocks for these facilities.

9. Indonesia

a. Background

The archipelago Republic of Indonesia has over 13,000 islands spreading over nearly 3,000 miles. The total land area covers 750,000 square miles. The population is currently estimated to be around 140 million, growing at 2.5 percent per annum. A map of Indonesia is shown as Figure III-B-10.

The labor force is around 45 million, with a very high percentage unemployed or underemployed. The islands of Java and Madura occupy about 9 percent of the total land area, but contain 65 percent of the total population. The population density on these two islands is over 250 persons per square mile.

Although many of the islands are very mountainous, large areas of the country are suitable for agricultural development. These could support a much larger population than at present. Government efforts to relocate people have had very limited success due to the close family relationships of Malay society. About 10 percent of the land area is devoted to agriculture. The food crops are rice, corn, sugar and sweet potatoes, and the principal plantation crops are rubber, palm oil, coffee, tea and spices. Large areas of the country are covered with tropical hardwood forests; timber (as logs, but more increasingly as cut timber and plywood) constitutes the country's second largest export commodity.

Oil is the dominant factor in the Indonesian economy, generating over 50 percent of government revenues and over 70 percent of total export earnings.

During 1976, new agreements were negotiated with the foreign oil companies active in Indonesia, resulting in terms far more favorable to the government. This, coupled with uncertainties about the effects of

FIGURE III - B - 10

INDONESIA

CHEM SYSTEMS INC.
PROJECT NO. 527 DATE

recent U.S. government tax rulings on the oil companies, has resulted in the lowest level of oil exploration activity in over three years.

Because Jakarta, the capital and largest city, and several other major cities are located on Java, the main market potential is on Java. However, the majority of the energy-related raw materials (oil, natural gas, hydro power and coal) are located on other islands or off-shore. As industrial development projects proceed, there will be a continuing struggle to shift the labor supply to the energy/feedstock source and political pressure to locate manufacturing operations in overpopulated, underemployed, land-scarce Java. The imbalance in location of population and raw materials for employment opportunities is one of the principal factors inhibiting the positive expansion of the Indonesian economy.

It is estimated that only about 15 percent of the population is in the money economy on a full-time basis, so the "have nots" represent a sizeable portion of the economy. The easy-going nature of the average Indonesian, his lack of education and training, lack of management ability and susceptibility to corruption at all levels, together with the high rate of population increase, have worked against positive economic growth.

During 1976, Indonesia made a significant recovery from the 1975 financial crisis in Pertamina, the state oil company. International reserves, nearly depleted as an immediate consequence of that crisis, have improved considerably. In the future, the government's ability to service its large debt and still maintain momentum in its development program depends largely upon whether Indonesia can maintain current oil production levels. Over the next several years, GNP growth in the 5-6 percent per year range is anticipated.

Industrial Development and Infrastructure

Infrastructure development and support facilities for industrial development in Indonesia are quite limited. The demands are so great and the capacity in funds, manpower and expertise so restricted that it is

unlikely the country will have a developed infrastructure by Western standards by the end of this century. In the greater Jakarta area and in some of the other cities in Java, an effort has been made to plan industrial sites and provide them with infrastructure such as road and/or rail access, water and power. Availability of unskilled labor is never a problem. As a result, most of the light to medium labor-intensive industries have clustered around Jakarta and other cities in Java. This has added to the already overcrowded situation in Tanjong Priok, the port for Jakarta. Priok handles about 60 percent of the total value of imports, but only about 4.5 percent of the exports. The difference is caused by the fact that most of Indonesia's exports are raw materials which are exported directly from the source.

If manufacturing growth in the Jakarta area continues to the point where exports become of sizeable volume, congestion will become worse. There is some talk about building a complete new port for Jakarta. Before this can ever be realized, however, the need for these additional facilities will be increased severalfold. To a greater or lesser extent, other ports in Indonesia are suffering from the same overload problems.

In remote areas, where mining and petroleum projects are located, the foreign companies are making their own investments in infrastructure and turning it over to the government or, as in the case of oil companies, infrastructure may be provided by Pertamina as part of the production sharing agreement.

Government Programs

The Indonesian government has state investments in many industries. The most prominent of these is through Pertamina, the national oil and gas company. Other state investments include mining, manufacturing and services. The Government also participates in joint ventures with private foreign companies.

The factor inhibiting private petrochemical investment is the limited amount of capital available from private sources for world-scale or even Indonesian-scale ventures.

It is government policy to encourage foreign capital and technology investment, and the following basic assurances and tax incensives are provided:

- Repatriation of current profits; expenses of foreign employees; depreciation of capital assets; compensation in case of nationalization.

- Exemption from corporate and dividend taxes for 6 years.

- Exemption of reinvested profits from corporate tax and dividend tax up to 5 years after date of reinvestment.

- Permission for accelerated depreciation of fixed assets.

b. Petrochemical Overview

Indonesia is a petroleum and natural gas exporting nation. In 1978, crude oil reserves were 10 billion barrels and production was 1.7 million barrels per day. In contrast, the country's refining capacity was 528,000 barrels per day. The country also has natural gas reserves estimated at 24 trillion cubic feet and is currently shipping LNG to Japan.

In addition to ammonia facilities, the only Indonesian petrochemical activity is the 20,000 metric ton per year polypropylene plant at Pladja, South Sumatra. Initial production began in early 1974. Two major petrochemical projects, an aromatics plant and an ethylene complex, were also planned, but the Pertamina collapse delayed their implementation by several years. At present, these projects are again being evaluated.

The collapse of Pertamina brought a change in government agencies responsible for petrochemical projects. As part of the program to rid Pertamina of ancillary activities, petrochemicals were assigned to the

Ministry of Industry. However, since the Ministry of Gas has responsibility of the disposition of natural gas liquids and the Ministry of Finance has responsibility for obtaining loans for all government agencies and corporations, these agencies must be in total agreement with a project before it can proceed.

10. People's Republic of China

a. Background

The People's Republic of China, frequently referred to as China, contains a quarter of the world's population. It is the world's third largest country in size. The People's Republic was proclaimed on October 1, 1949, by the Chinese Communist Party, which set for itself the awesome task of uniting and mobilizing a population impoverished and exhausted by 37 years of domestic chaos, war and foreign invasion in the construction of a modern industrial socialist society.

The territory governed by the Chinese People's Republic includes China Proper (the 18 historic provinces of imperial China), Inner Mongolia, Sinkiang, the Northeast (Manchuria) and Tibet. The country's vast area of 3.69 million square miles (excluding Taiwan) is slightly larger than that of the United States. China's immense land mass forms the greater part of central and eastern Asia.

China's demographic statistics are terribly inadequate. It has been estimated that in 1978 the population of China reached 863 million. It is also estimated that 40 percent of the population is under 15 years of age. This means that there is a much larger dependent population in China than in the economically advanced nations, presenting serious problems in education and employment. Because climate and soil limit agriculture to only one tenth of the land area, some 90 percent of people live on 40 percent of the land area.

Government Programs

After coming to power, the Communists placed overall long-range planning in the hands of the state planning commission, under the national people's congress of the state council. Short-range planning was given to the state economic commission. Other commissions were also formed. The general bureau for the supply of raw materials was formed in 1956 to control resources. Together with the state construction commission and the state technological commission, it helped the state planning commission to formulate five-year plans. Many changes in the commissions have taken place since then, but the general pattern has been the same. Although the central government makes plans, they are implemented by provincial authorities.

Trade

The United States officially recognized the People's Republic of China (PRC) on January 1, 1979. Although trade in 1978 exceeded $1 billion, unresolved trade and commercial issues continue to hamper its growth. Neither country enjoys most-favored nation (MFN) tariff treatment and China does not have access to Export-Import Bank loans and guarantees or other financial programs of the U.S. Government, except for CCC (Commodity Credit Corporation) agricultural credits. The unresolved claims and assets issue inhibits or precludes direct banking relationships, direct shipping or airline connections in flag carriers and the exchange of trade exhibitions. It is the policy of the U.S. government to seek resolution of these and other barriers to the full development of trade and commercial relations.

China's leaders view international trade as an important factor in transforming China into a modern industrial state, as well as an instrument to foster the overall political and economic goals of making China a strong, unified nation capable of exercising leadership in Asia and the world. Import policy is directed at the acquisition of capital

goods that embody the modern technology needed to develop China's industry. Trade also is used to overcome serious shortcomings and bottlenecks in domestic production.

A prevailing theme in PRC foreign trade policy has been economic independence. Until recently, China has avoided long-term foreign credit, preferring to scale imports to the amount of foreign exchange available from export earnings. However, the goal to thoroughly modernize China by the year 2000 and the objectives of the Ten-Year Plan (1976-1985) are so ambitious that China has found it necessary to rely on some foreign financing. Until recently, the PRC had attempted to become self-sufficient through development of its own productive capacity; now it realizes that the industrialization program cannot be successfully completed in the desired time period without a major infusion of foreign plant, equipment and technology. Generally, the PRC seeks to avoid becoming too dependent on any one country as a source of trade.

Development of foreign trade and economic relations with most nations of the world is an important part of China's present policy to maximize the potential contribution of foreign trade to its economic development. China now has trading relations with more than 150 countries. To date, China has joined very few international economic or financial organizations, but Beijing's interest in arrangements that promote trade should increase as the country becomes more involved in international commerce.

b. Petrochemical Overview

Until recently, petrochemical production in the PRC was virtually nonexistent. At present, however, petrochemical production is growing rapidly through the importation of plants and technology. Fertilizer production increased sharply through the erection of a series of ammonia plants, which were given first priority. In addition, facilities for ethylene and derivatives manufacture, synthetic fibers and intermediates and plastics have been completed or under construction. In the petrochemical area, the strategy in the PRC is to import plants and

technology instead of products. As a result, product imports are anticipated to be relatively modest, and the PRC, despite large current local demand, has become a modest exporter in order to earn foreign exchange.

C. Factors Influencing Petrochemical Exports into the Pacific Basin Region

The export of petrochemicals from a U.S. plant to the Pacific Basin regions will depend upon a number of factors such as local supply/demand considerations, pricing for products imported, governmental regulations, regional associations and local business practices. The situation which will influence petrochemical imports in each of the Pacific Basin countries is presented below.

Japan

Japan, as the free world's second largest petrochemical producer, is anticipated to have ample supply of virtually every petrochemical made in essentially world-scale facilities. However, for most petrochemicals, demand is very high in relationship to the output from a single plant, so that large imports from a West Coast plant would only amount to a small percentage of overall demand. Since domestic prices are relatively high and duties are nominal, the country could theoretically be a good export market.

Heretofore, Japanese business practices have precluded the potential for significant imports, except under special circumstances. The trading companies have strong ties to the domestic producers; thus they would not import material which would adversely affect domestic industry. In addition, the interrelationship between the Japanese manufacturers, the trading companies and the banks makes it difficult for a consumer to import materials outside established channels.

As a result of sharp crude oil and naphtha price increases since the 1973-1974 oil embargo, Japan has become a high-cost petrochemical producer. This has changed the long-term strategy for Japanese firms to one of emphasizing specialty instead of commodity chemicals for future growth and to importing those products in which Japanese firms are not

cost competitive from assured, low-cost sources of supply. As a result, Japan could be a significant market for chemicals for Alaska, and Japanese firms are potential investors in an Alaskan petrochemical project.

Korea and Taiwan

Korea and Taiwan both have developing petrochemical industries. A dual pricing structure for the products generally exists, such that material exported or processed into goods for export is valued at world market prices, while material intended for domestic consumption is generally valued at that price required for the producer to obtain a satisfactory return on his investment. Both countries have duties and other taxes which result in effective duties of about 30-50 percent for the commodity petrochemicals. This effectively precludes importation of material, except in duty drawback situations and situations when local supply is nonexistent or is insufficient to meet demand. In both countries, consumers have tended to use locally produced material whenever possible; as a result, significant petrochemical import opportunities exist only for those products where domestic supply is insufficient to meet demand.

Hong Kong

Hong Kong has no duties on imports and there is no protection for domestic industry. As a result, there are no impediments to exports from a U.S. facility.

ASEAN Countries

The ASEAN countries are attempting to develop (1) a trade zone coupled with preferential internal duties and (2) an apportionment of facilities among the countries. With respect to petrochemicals, the individual countries are promoting their projects, and rationalization of the situation on a logical basis appears unlikely within the next several years.

The Philippines, Indonesia, Thailand and Malaysia have significant protection for domestic industry. Petrochemical imports will thus be limited to products where local production is insufficient to meet demand and to duty drawback situations. However, it is anticipated that other countries within the ASEAN group will eventually have a preferable duty position. This will place a U.S. producer at a competitive disadvantage vis-a-vis an ASEAN country producer in those markets. As a result, over the longer term, the potential for imports will tend to be governed more by the supply shortfall within the group rather than on a country-by-country basis.

Singapore is a free port and, like Hong Kong, has no duties or restrictions on petrochemical importation. Since most petrochemical consumption is related to product exports, local production or production in other ASEAN countries would not affect the ability to export from the U.S. to Singapore.

People's Republic of China

The PRC purchases petrochemicals on a spot or short-term contract basis. The quantities purchased are relatively modest and can be quite variable depending upon price and the country's hard currency situation. As a result, the PRC cannot be considered a significant long-term market for petrochemicals from Alaska.

IV. PRODUCT ANALYSES

This section of the report presents market analyses for ethylene, propylene and their major derivatives in the Pacific Rim market.

A. Low Density Polyethylene

1. West Coast Market

a. Demand

The 1978 market for LDPE resin in the West Coast areas of the United States and Canada was estimated at over 900 million pounds. An anticipated overall growth of 7.9 percent per year over the next 12 years will result in a market of over two billion pounds by 1990. Film will account for about 65 percent of the total demand for LDPE resin throughout the study period of 1978-1990, as shown in Table IV-A-1. The Canadian market constitutes about 5 percent of the total.

TABLE IV-A-1

WEST COAST LOW DENSITY POLYETHYLENE DEMAND, 1978-1990
(Million Pounds)

Western U.S.	1978	1980	1985	1990	AAGR, %* (1978-1990)
Film and sheet	580	700	1,060	1,500	8.2
Injection molding	125	145	200	260	6.3
Wire and cable	85	100	145	210	7.8
Extrusion coating	50	55	75	95	5.5
Other uses (including blow molding and pipe)	55	70	115	165	9.6
Total Western U.S.	895	1,070	1,595	2,230	7.9
Western Canada	40	45	65	90	7.0
Total	935	1,115	1,660	2,320	7.9

* Average annual growth rate.

AGO 559619

Western U.S.

Film and Sheet

Film is by far the largest market for LDPE on the West Coast, with 1978 consumption of about 580 million pounds. This market is anticipated to more than double by 1990.

Film is used in many forms of packaging and wrap, ranging from food to garbage bags. Shrink and stretch films are also used in packaging. Substantial quantities of film are also used in agricultural applications. Film thickness varies from 0.5 mil for dry cleaning and garment bag applications to 10 mils and higher for construction uses. Ethylene-vinyl acetate copolymer films containing low percentages of the comonomer to achieve improved impact strength and clarity are used for produce bags, shipping sacks and liquid packaging. Growth in film demand on the West Coast is expected to parallel that of the U.S. market. Considerable market potential is anticipated within the region for injected-in film for unitizing containers.

From time to time, the West Coast has felt the pressure of film and bag imports from the Far East. Currently, imports represent a relatively low percentage of overall demand. Increased imports are not anticipated to materially influence the growth of the West Coast industry.

About half of the resin market for film is in southern California. Northern California, Washington, Oregon and Idaho are other significant consuming areas. Major consuming firms are listed in Table IV-A-2.

Injection Molding

There are numerous molders of polyethylene; the major categories are lids for convenience and other foods, toys, housewares and food containers. Housewares account for about 40 percent of the total injection molding

TABLE IV-A-2

MAJOR U.S. WEST COAST USERS OF LDPE RESIN FOR FILM PRODUCTION, 1978
(Million Pounds)

Company	Location
Arco	Long Beach, CA
Crown Zellerbach	San Leandro, CA
	Los Angeles, CA
	Portland, OR
Mobil	Woodland, CA
Shields Bag	Yakima, WA
Weyerhaeuser	two locations - WA
Potlatch	Lewiston, ID
Bemis Bag	Richmond, CA
CT Film (Dart)	Santa Ana, CA
Monsanto	Santa Ana, CA
Dow	Torrance, CA
Golden West	Tustin, CA
Ethyl Corporation	Glendora, CA
St. Regis	Union City, CA

market of 125 million pounds, with lids and toys accounting for another 40 percent. The West Coast injection molding market is anticipated to more than double by 1990.

Housewares are dominated by Fesco (Cities Service) of Tustin, California, and Dart Industries (Tupperware) with its Idaho plant. Processors of lid resins include Amoco, Triplas, Molded Container and Continental Can.

Wire and Cable

The wire and cable market for LDPE was about 85 million pounds in 1978 and is expected to reach 210 million pounds by 1990. The product finds use in telephone and coaxial cables. It is used as both an insulator and a dielectric. High-voltage cables also utilize polyethylene for insulation. The major user of polyethylene was Western Electric in Phoenix, AZ. The major LDPE consumers for wire and cable extrusion are shown in Table IV-A-3.

TABLE IV-A-3

MAJOR U.S. WEST COAST USERS OF LDPE RESIN FOR WIRE AND CABLE

Company	Location
Western Electric	Phoenix, AZ
Kaiser Aluminum	Rockland, CA
Alcan Cable West	Rockland, CA
Reynolds	Longview, WA
Anaconda	Orange, CA
Pirelli	-
Arizona Wire	Phoenix, AZ
ITT Cable Hydrospace	San Diego, CA
Hatfield Wire	Phoenix, AZ

Extrusion Coating

The extrusion coating market for LDPE was about 50 million pounds in 1978 and is expected to almost double by 1990. The major application is in the coating of paperboard and other substrates. Ethylene-vinyl acetate copolymers are used by some converters to improve heat sealability. Companies such as Crown Zellerbach (San Francisco, CA), Guardian Packaging (Newark, CA) and Georgia Pacific (Portland, OR) are large producers of polyethylene-coated paperboard.

Other Uses

This category, including pipe, blow molding, and other uses, amounted to 55 million pounds in 1978. Growth is forecast at 9.6 percent per year, for a 1990 market of 165 million pounds.

Western Canada

The LDPE market in Western Canada was about 40 million pounds in 1978. Demand is forecast to increase at about 7 percent per year and reach 90 million pounds by 1990. Film is the major market within the area, but pipe and extrusion coated materials are also produced. Significant LDPE

consumers include Capital Plastics, Surrey, BC (film), Pacific Plastics, Vancouver (pipe), Seaforth Plastics, Vancouver (film) and Western Concord, Vancouver (film). There is no captive LDPE consumption in the West Canadian market.

b. Supply

There is only one producer of low pressure polyethylene on the U.S. West Coast, namely Union Carbide, with a capacity of 140 million pounds per year at Torrance, CA. This compares with a total U.S. capacity of about 8.5 billion pounds. The major part of the West Coast market is supplied from plants in Texas and Louisiana. The output from the Union Carbide facility is primarily consumed on the West Coast, but some is also shipped to other areas. This unit is small and relatively old, having been built in the 1950s.

Several of the U.S. producers of resin are significant suppliers to the West Coast. Union Carbide, Dow, USI, Exxon and Arco are the five largest suppliers, and they supply about two-thirds of the market.

There are no LDPE producers in British Columbia, but CIL has a 70 million pound per year unit at Edmonton, which supplies consumers in British Columbia. Other suppliers include Dow of Canada, DuPont Canada, Union Carbide Canada, Mitsubishi and some of the U.S. suppliers.

c. Captive Market

About 20 percent of the 895 million pound U.S. West Coast market for LDPE is captive. However, there are no captive consumers in Western Canada. Arco, Mobil, Dart and Cities Service (Fesco) are the major captive users. No significant changes in this percentage are foreseen over the study period.

d. Pricing

Low density polyethylene is sold on a delivered price basis in the U.S., with West Coast prices equivalent to those for the remainder of the U.S. In July 1979, LDPE prices were increased to 35.5 cents per pound for the liner grade. General-purpose grades are 36.5 cents per pound, while injection-molding grades are 38.5 cents per pound. Prices have increased by over one-third in the past year, due primarily to higher prices elsewhere in the world and increased domestic and export demand. Future prices will tend to reflect only increases in costs, since the supply/demand situation is anticipated to remain relatively good.

Liner-grade polyethylene in Canada sold for $0.41 (Canadian) per pound delivered in hopper cars in September 1979. Bagged material is priced 6 cents per pound higher, while the general-purpose resin sells for 2.5 cents per pound more than the liner grade. Prices are anticipated to remain slightly above U.S. levels. The duty on LDPE is 10 percent ad valorem.

2. Pacific Basin Market

a. Japan

Demand

The domestic demand for low density polyethylene homopolymer and ethylene-vinyl acetate copolymer in Japan is forecast to increase from 894,000 metric tons in 1977 and 960,000 metric tons in 1978 to 1,770,000 metric tons in 1990, as is shown in Table IV-A-4. Exports were about 286,000 metric tons in 1977 and 231,000 metric tons in 1978, including copolymer. Exports are anticipated to decrease due to increased penetration of Far Eastern markets by U.S. producers, startup of new facilities in the region, and higher production costs in Japan.

TABLE IV-A-4

JAPANESE LOW DENSITY POLYETHYLENE DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
Film	515	555	625	800	975	4.8
Laminates	100	108	125	175	225	6.3
Wire and cable	62	66	73	92	115	4.7
Injection molding	75	80	95	130	170	6.5
Pipe	6	6	7	8	10	4.3
Blow molding	33	35	40	50	60	4.6
Others	103	110	125	165	215	5.7
Domestic demand	894	960	1,090	1,420	1,770	5.2
Exports	286	231	200	150	100	(7.2)
Total demand	1,180	1,191	1,290	1,570	1,870	3.8

Film is the largest segment of the LDPE market, representing nearly 50 percent of domestic demand. Historically, this has been a major demand growth area, but demand is expected to grow only at about 5 percent per year throughout the study period. This is due to increased imports from Korea and Taiwan, increased penetration of thin high density polyethylene film, which is capturing some traditional low density polyethylene markets, and conservation brought about by higher prices. Usage in lamination, injection-molded articles and blow-molded articles is also anticipated to show moderate growth. On the other hand, growth of wire and cable uses is expected to be relatively slow.

Supply

The current low density polyethylene capacity in Japan is 1,520,000 metric tons per year, as shown in Table IV-A-5. At present, no expansions are under way. However, it is felt that capacity will probably increase by 100,000 metric tons per year by the mid-1980s, since Mitsubishi Petrochemical has been considering a facility and some other firms have long-range plans to expand in LDPE.

TABLE IV-A-5

JAPANESE LOW DENSITY POLYETHYLENE PRODUCERS, 1978
(Thousand Metric Tons per Year)

Company	Capacity
Mitsubishi Petrochemical	250
Sumitomo Chemical	242
Mitsui Polychemical	160
Nippon Unicar	165
Ube Kosan	140
Asahi Dow Chemical	124
Toyo Soda	158
Mitsubishi Chemical	97
Nippon Petrochemical	64
Showa Petrochemical	120
Total	1,520

Supply/Demand Situation

The potential supply/demand balance for LDPE in Japan is presented in Table IV-A-6. Basically, Japan is anticipated to have sufficient LDPE capacity to be self-sufficient until the mid-1980s. However, the higher cost of production could result in displacement of Japanese production with imported material. By the mid-1980s, Japan could be importing 100,000-200,000 metric tons per year.

TABLE IV-A-6

POTENTIAL SUPPLY/DEMAND BALANCE FOR LOW DENSITY POLYETHYLENE IN JAPAN
(Thousand Metric Tons)

	1978	1980	1985	1990
Potential supply*	1,520	1,520	1,620	1,620
Forecast demand	1,191	1,290	1,570	1,870
Surplus/(deficit)	331	230	50	(250)
Operating rate, %	78	85	97	

* 100 percent of nameplate capacity.

Pricing

LDPE prices in Japan are higher than world prices. Delivered prices were 215 yen per kilo (44.4 cents per pound) in late June 1979 for film-grade resin. Prices for other grades are somewhat higher. LDPE imports are subject to a duty of 28 yen per kilo.

b. Korea

Demand

The Korean demand for low density polyethylene was 135,000 metric tons in 1977 and 160,000 metric tons in 1978. Demand is forecast to increase to 205,000, 305,000 and 420,000 metric tons by 1980, 1985 and 1990, respectively. This represents an average annual growth of 8.4 percent over the period. Film and bags for fertilizer, agricultural and general packaging use represent about 80 percent of the market. Only about 10 percent of the converted product production is exported, but considerably larger quantities are exported in the form of packaged goods.

There are about 400 processors of low density polyethylene in Korea. The major consumers are listed in Table IV-A-7. These firms represent about half of Korean consumption.

TABLE IV-A-7

MAJOR KOREAN CONSUMERS OF LDPE

Ajin
Hyon Dae Chemical
Il Shin Chemical
Sam Yung Chemical
Hwa Sung Vinyl
Daihan
Sun-A Plastic
Lucky Ltd.
Chin Yang
National Plastic

Supply

Korea Pacific Chemical, a Dow Chemical affiliate, is the sole producer of low density polyethylene in Korea; its plant at Ulsan is rated at 70,000 metric tons per year. The firm is building a 100,000 metric ton per year unit at Yeosu, which is scheduled to be on stream in 1979. Union Carbide has also entered into a joint venture with Lucky Petrochemical to build a 150,000 metric ton per year LDPE plant at the new Yeosu complex. Start-up is expected in 1982-1983, but could be subject to delay.

Production at the Korea-Pacific plant in 1978 was 63,000 metric tons of material. Imports were 98,000 metric tons, which were handled by Korea-Pacific for the industry association.

Supply/Demand Situation

The supply/demand situation for low density polyethylene in Korea is shown in Table IV-A-8. Korea is anticipated to be a net importer in the early 1980s, but will be self-sufficient when the third unit comes on stream. Based upon projections and current philosophy, it is unlikely that Korea would build a fourth unit until the end of the 1980s, and thus they would again be an importer in the late 1980s.

TABLE IV-A-8

POTENTIAL SUPPLY/DEMAND BALANCE FOR LOW DENSITY POLYETHYLENE IN KOREA
(Thousand Metric Tons)

	1977	1978	1980	1985	1990
Potential supply	70	70	170	320	420*
Forecast demand	135	160	205	305	420
Surplus/(deficit)	(65)	(90)	(35)	15	0
Actual production	55	63			

* Anticipated new unit.

AGO 559628

Pricing

LDPE pricing from domestic units is set by the government at levels sufficient to yield a reasonable return in the facilities, and it tends to be from 20 to 30 percent above world prices. Imports are normally made on a monthly tender basis at very attractive prices; however, with the resin shortages in recent months, Korea has had to pay premium prices for imported material. Imports are subject to import duties, a handling charge, defense tax and a commodity tax. However, duty drawback is obtained on material converted for export.

c. Taiwan

Demand

In 1977 and 1978, the total demand for low density polyethylene in Taiwan was 89,000 and 93,000 metric tons, respectively. This included resin utilized in domestic markets, produced for export, and imported for conversion into products for export. The domestic market accounts for about three-quarters of domestic demand. Film and bags constitute about 80 percent of this market.

Approximately 20-25 percent of the total resin demand is processed into goods for export. Taiwan is facing increased competition from other countries, such as Singapore, in film and bag markets. In addition, the U.S. film and bag producers are not about to let imported products acquire more than a small percentage of the market. As a result, the processing for export market is anticipated to grow only at about 5 percent per year for the next few years and then begin to level off. This is less than the growth in polyethylene consumption.

The domestic demand for low density polyethylene is forecast to increase from 70,000 and 75,000 metric tons in 1977 and 1978 to 85,000, 115,000 and 150,000 metric tons in 1980, 1985, and 1990, respectively. This represents an average annual growth rate (from a 1978 base) of 5.8

percent. Exports are expected to increase significantly in the early 1980s due to the desire to utilize the increased capacity available. A breakdown of consumption is presented in Table IV-A-9.

TABLE IV-A-9

TAIWAN DEMAND FOR LOW DENSITY POLYETHYLENE
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
Total domestic demand	70	75	85	115	150	6.0
Exports	19	18	50	50	50	-
Total demand	89	93	135	165	200	6.6

Supply

The current Taiwanese capacity for low density polyethylene is 90,000 metric tons. Announced expansions should increase capacity to 215,000 metric tons by the end of 1979, as is shown in Table IV-A-10. Actual potential supply is estimated to be approximately 90 percent of nameplate capacity.

TABLE IV-A-10

TAIWAN LOW DENSITY POLYETHYLENE PRODUCERS, 1978
(Thousand Metric Tons)

Company	Location	Capacity	Expansions
Asia Polymer	Kaohsiung		75 (1979)
USI Far East	Kaohsiung	90	50 (1979)
		90	125

USI Far East was once completely owned by National Distillers and Chemical Corp., but it is now 50 percent owned by local Chinese interests. The firm produces for the local market and exports throughout Southeast Asia. The plant, which reached its current size in a few stages, is in the process of expansion by 50,000 metric tons. This expansion will be completed in 1979.

Asia Polymer is owned by China Gulf Plastics (an affiliate of Gulf Oil Corp.), Chinese Petrochemical Development Corp. (government-owned), and a

number of plastics fabricators. The firm has completed a 75,000 metric ton per year unit.

Supply/Demand Situation

The supply/demand balance for LDPE is shown in Table IV-A-11. After the current expansions are completed, there will be sufficient capacity in Taiwan to meet demand growth throughout the study period. As a result, there will be little opportunity for sales to Taiwanese firms except under special situations, such as imports for processing into products which will be exported.

TABLE IV-A-11

POTENTIAL SUPPLY/DEMAND BALANCE FOR LOW DENSITY POLYETHYLENE IN TAIWAN
(Thousand Metric Tons)

	1977	1978	1980	1985	1990
Potential supply*	81	81	194	194	194
Forecast demand	89	93	135	165	200
Surplus/(deficit)	(8)	(12)	59	29	(6)

* 90 percent of nameplate capacity.

Pricing

The domestic prices in Taiwan are normally substantially above Southeast Asian market prices. However, resin sold to processors for conversion to fabricated articles for export are sold at Southeast Asian market prices. LDPE imports are subject to high duties and taxes, but duty drawback can be obtained on processing for export situations.

d. Hong Kong

Hong Kong has no domestic low density polyethylene production, and it is very unlikely that this product would ever be produced in the colony. However, Hong Kong is a major consumer of the product (use in 1978 is estimated at 90,000 metric tons). Film is the major outlet for low

density polyethylene in Hong Kong, representing about 65-70 percent of overall consumption.

Consumption is expected to reach 100,000, 115,000 and 135,000 metric tons in 1980, 1985 and 1990, respectively. Domestic use for the product is expected to grow strongly for the next few years, reflecting economic growth in the colony. However, processing of low density polyethylene for export, which constitutes about 60 percent of the market, is anticipated to remain about constant. This is due to the nature of Hong Kong's economy: it specializes in the development of techniques to produce fabricated articles rather than in producing larger quantities of a given product.

There are over one thousand polyethylene consumers, most of whom order only a few bags at a time. In 1978, Japan, with exports of 50,000 metric tons to Hong Kong, had over 50 percent of the market. Other suppliers were U.S., Italian, French and German firms. There is no duty on LDPE imports to Hong Kong, and the material is normally sold at the Southeast Asian market price.

e. ASEAN Countries

LDPE demand in the ASEAN countries is anticipated to increase from 155,600 and 172,000 metric tons in 1977 and 1978, respectively, to 421,000 metric tons in 1990, as shown in Table IV-A-12. Film and bags represent most of the demand for the product.

TABLE IV-A-12

ASEAN COUNTRY LOW DENSITY POLYETHYLENE DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
Philippines	35	41	60	85	105	9.6
Singapore	24	25	28	36	46	5.2
Malaysia	23.6	25	28	37	50	6.0
Thailand	28	30	35	50	70	7.3
Indonesia	45	51	65	100	150	9.4
	155.6	172	188	308	421	7.7

At present, there are no producers of LDPE in the ASEAN region. A 100,000 metric ton per year plant, in which Sumitomo would have a dominant interest, is planned as part of a petrochemical complex in Singapore. The facility is scheduled to be onstream in late 1982. A 90,000 metric ton per year plant is planned for the Philippines, in which USI Far East would be the foreign partner. A facility of similar size is planned for Thailand by Chinese interests. These latter two projects are based on imported ethylene and are not firm at present.

f. People's Republic of China

In the past three years, the People's Republic of China has begun to install LDPE plants. At present, capacity totals about 200,000 metric tons; as a result, imports have fallen to relatively low levels, and the PRC has exported small quantities to Hong Kong. In future years, only modest imports are foreseen, so this market cannot be viewed as a significant secure market for an Alaskan facility.

3. Conclusions

Opportunities for an Alaskan Plant

The supply and demand for LDPE on the West Coast and in the Pacific Basin are summarized in Table IV-A-13.

TABLE IV-A-13

LOW DENSITY POLYETHYENE

	Demand				Capacity, per year	
	1978	1985	1990	AAGR, %	1978	Future
		(Million Pounds)				
West Coast	935	1,660	2,320	7.9	140	0
		(Thousand Metric Tons)				
Japan	960	1,420	1,770	5.2	1,520	1,620
Korea	160	305	420	8.4	70	320
Taiwan	75	115	150	6.0	90	215
Hong Kong	90	115	135	3.4	0	0
ASEAN Countries	172	308	421	7.7	0	100*

* Singapore project. Other projects possible.

AGO 559633

During the 1980s, it is expected that new grass-roots low density polyethylene facilities will have to have a capacity of at least 500 million pounds per year in order to be competitive.

Due to the established position of numerous suppliers, it is anticipated that a firm with Alaskan production could reasonably expect to capture only 15-20 percent of the merchant market on the West Coast. This would equate to 210-280 million pounds of the 1,400 million pound merchant market forecast within the region for 1985. By 1990, with the anticipated demand increase, sales should grow to 300-400 million pounds.

LDPE imports into Hong Kong and the ASEAN countries will total about 700 million pounds by 1985. About 40 percent of this demand should be met by exports from Japan and Taiwan. However, an Alaskan facility would be in a good position to capture a share of the remaining market. In addition, Japan, while it possesses sufficient LDPE capacity at present, is a relatively high cost producer. As a result, it could be advantageous to supplant domestic production with imports. Levels of about 200 million pounds per year would not be unreasonable. From a standpoint of market size and trends, production of LDPE in Alaska is viable.

B. High Density Polyethylene

1. West Coast Market

a. Demand

During 1978, consumption of HDPE within the West Coast region was estimated at 500 million pounds. California alone is estimated to have consumed more than 350 million pounds. Growth over the next 12 years is forecast at 10.3 percent per year, for a 1.6 billion pound market in 1990.

Blow molding accounts for about 35 percent of total HDPE demand in the West Coast region. This percentage is expected to be maintained over the entire study period. The consumption of HDPE, by application, from 1978 through 1990 is indicated in Table IV-B-1.

TABLE IV-B-1

WEST COAST HIGH DENSITY POLYETHYLENE DEMAND, 1978-1990
(Million Pounds)

Western U.S.	1978	1980	1985	1990	AAGR, % (1978-1990)
Film and sheet	40	65	160	250	16.5
Injection molding	110	135	210	325	9.4
Wire and cable	25	28	40	65	8.2
Blow molding	175	220	355	520	9.5
Pipe and conduit	60	80	135	215	11.2
Other uses (including roto molding)	70	87	130	175	7.9
Total Western U.S.	480	615	1,030	1,550	10.3
Western Canada	20	25	35	60	9.5
	500	635	1,065	1,610	10.3

Western U.S.

Film and Sheet

This category accounted for an estimated 40 million pounds in 1978, about 7 percent of the total U.S. West Coast market. HDPE film is used in

various applications such as merchandise bags, shipping sacks, coextruded food packaging and tissues. In essence, much of HDPE film's use is as a replacement for paper in, for example, bread wrap and fruit wrapping. In addition to typical plastics processors - Guardian Packaging (Newark, CA), Richmond Division of Pak-Well (Redlands, CA), Alchem (La Miranda, CA), Lustro (Valencia, CA), and LTD Packaging (Santa Fe Springs, CA) - companies that have traditionally made paper products, such as Crown Zellerbach, are also involved in the production of HDPE film. Film consumption alone on the West Coast area is estimated at 30 million pounds.

Sheet usage in the region is estimated at approximately 10 million pounds. The major application is in thermoforming for such diverse products as large containers, tote bags, toys and childrens' swimming pools. Gage Industries (Lake Oswego, OR) is the major sheet fabricator, but Lustro and Alchem are also manufacturers.

Injection Molding

About 25 percent of the U.S. West Coast HDPE resin consumption is used in injection molding for food containers, nursery tubs, toys, shipping drums and containers. Food containers and packaging injection molded products constitute about a third of this market. Production is primarily accounted for by about eight companies, with Crown Zellerbach, Molded Container, Gregg Foods and Owen-Illinois among the largest.

Nursery tubs and flower pots constitute about a quarter of the market. Anaheim Plastics and J.S. McConky are major producers.

Wire and Cable

Usage of HDPE resin in this category was estimated at 25 million pounds during 1978. About ten companies in the U.S. West Coast region use HDPE for wire insulation. They include Pacific Electricord (Gardena, CA), National Wire and Cable (Los Angeles, CA) and Raychem (Menlo Park, CA). However, the largest consumer is Western Electric of Phoenix, AZ, with an estimated annual usage of at least 15 million pounds.

A growth rate of 8.2 percent per year over the 1978-1990 period is forecast for the wire and cable extrusion market in the West Coast region.

Blow Molding

This is the major HDPE market in the West Coast, accounting for 175 million pounds of resin in 1978. Growth in this category is forecast at 9.5 percent per year, resulting in an anticipated market of 520 million pounds in 1990. About 50 firms blow mold HDPE in this region, with perhaps 20 of these accounting for 70 percent of total blow molding resin consumption. Many of the blow molders process resin for captive operations, such as Altadena Dairies, Carnation Dairies, Purex and Revlon. In addition, many of the major national packaging companies are involved, including American Can, Continental Can, Georgia Pacific, Monsanto and Owens-Illinois. Among the other processors are the following high volume companies - Born Free Plastics, Polytainer, Molded Container, Spokane Presto Log and Plastic Industries. Large (up to 55 gallon) drums are being blow molded by several companies. This market accounts for about 15 million pounds of the total consumption of blow molding resin. Born-Free, Applied Chemical Technology and Ziffco are the major producers of large drums.

Pipe and Conduit

Usage of HDPE resin in this application was estimated at 60 million pounds in 1978. This market is forecast to grow to 215 million pounds by 1990, an average annual growth rate of 11.2 percent over the period. The products are used in potable water and gas lines and in the production of 12" corrugated pipe. During 1973, corrugated pipe accounted for about half of the market, with gas and water distribution and oil patch pipe utilizing the rest.

Potable water pipe producers are Phillips Products (Watsonville, CA), AB&I Plastics (Newark, CA), Kerona Inc. (Santa Ana, CA), Pacific Plastic

Pipe Co. (Beaverton, OR), Portco Corp. (Vancouver, CA), Superlon Pipe Corp. (Tacoma, WA), Swanson Co. (Phoenix, AZ), Wes Flex Mfg. (Richmond, CA) and Western Plastics (Tacoma, WA and Denver, CO).

Other Uses

These include rotational molding for recreational vehicles, golf bags, crock pot covers and decoys. Companies involved in roto molding are Hollowform (Woodland Hills, CA), Rotoform (Santa Cruz, CA) and Peco (Portland, OR). There is also some extrusion coating and foam usage of HDPE. By 1990, the total "other" category is expected to reach 175 million pounds from the current level of 70 million pounds.

Western Canada

The HDPE market in Western Canada was 20 million pounds in 1978. Demand is forecast to increase at about 9.5 percent per year and reach 60 million pounds by 1990. Pipe, large containers, bottles and molded articles are produced within the area. Significant HDPE consumers include Capilano Plastics (large containers), Columbia Plastics (custom molder) and Pacific Plastics (pipe), all located in Vancouver.

b. Supply

There are no producers of HDPE resin on the U.S. West Coast, but there are 13 producers in the United States with a capacity totalling over 5 billion pounds. Announced expansions total about another 1 billion pounds.

Several of the U.S. producers of resin are significant suppliers to the U.S. West Coast. Among these, Phillips, Soltex, Chemplex, Arco and Allied Chemical account for about 70 percent of the total market.

There are no HDPE producers in Western Canada. The Canadian HDPE producers - Dow Chemical of Canada, DuPont Canada and Union Carbide Canada - supply the Western Region. In addition, firms such as Mitsui, Soltex, Phillips and Hoechst are also active in the region.

c. Captive Markets

The captive market for HDPE on the West Coast was about 50-60 million pounds in 1978, or approximately 10-13 percent of the overall market. The major captive user was Phillips through its pipe operation and through the Sealright container operation. Owens-Illinois, a 50 percent owner of National Petrochemical, is a significant factor in the blow molding market, and Amoco is also a producer of foamed food containers. No appreciable change in the captive share of the market for HDPE in the region is foreseen.

There is no captive HDPE consumption in British Columbia, but Phillips has an extruded pipe operation in Calgary.

d. Pricing

In July 1979, the U.S. prices for blow-molding, injection-molding and general-purpose extrusion grades of HDPE were 36.25 cents per pound, delivered. The same prices prevail on the U.S. West Coast as in the remainder of the United States. Prices increased about 25 percent since mid-1978. Further price increases should be related primarily to cost increases.

In Canada, the commodity grades of HDPE sold for $0.455-0.491 (Canadian) per pound delivered in bags in September 1979. Prices are anticipated to remain slightly above U.S. levels. The duty on LDPE is 10 percent ad valorem.

2. Pacific Basin Market

a. Japan

Demand

The domestic demand for high density polyethylene in Japan is forecast to increase from 320,000 metric tons in 1977 and 438,000 metric tons in 1978 to 550,000 metric tons in 1980, 780,000 in 1985 and 990,000 by 1990. Japan has been a substantial HDPE exporter, with exports totaling 176,000 metric tons in 1978. However, they are anticipated to decrease somewhat over the study period. As a result, total HDPE demand should increase from 614,000 metric tons in 1978 to 1,060,000 metric tons in 1990. This represents an average annual growth of 4.6 percent. The Japanese demand by end-use for this product is presented in Table IV-B-2.

TABLE IV-B-2

JAPANESE HIGH DENSITY POLYETHYLENE DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
Demand						
Injection molding	90	120	150	200	250	6.3
Blow molding	70	86	100	140	185	6.6
Film	50	95	130	210	280	9.4
Tape	10	14	17	25	30	6.6
Slit film yarn	29	34	45	55	65	5.5
Fiber	25	32	39	15	65	6.1
Pipe	7	9	11	15	20	6.9
Miscellaneous	39	48	58	80	95	5.9
Total domestic demand	320	438	550	780	990	7.0
Exports	182	176	130	100	70	(8.0)
Total demand	502	614	680	880	1,060	4.6

Injection molding applications are the largest segment of the HDPE market, with the major application being in the production of

containers. Demand is anticipated to increase about 12 percent per year in the 1978-1980 period, from 120,000 to 150,000 metric tons. Demand is expected to reach about 200,000 metric tons by 1985 and 250,000 metric tons by 1990, which represents a growth rate of 6.3 percent per year over the 1978 to 1990 period.

Blow molding is a relatively mature market, with demand growing an average of 6.6 percent over the study period.

Thin HDPE film has made substantial inroads in Japan in applications such as bags. Most of this market has been at the expense of LDPE. Overall HDPE film demand was about 95,000 metric tons in 1978, an increase of 90 percent over 1977. HDPE film is anticipated to increase to nearly 280,000 metric tons by 1990. Mitsui Petrochemical, Showa, Nissan, Asahi and Mitsubishi Chemical are among the producers of resins for this application. Package tape is currently a 14,000 metric ton per year market, which is anticipated to grow slightly above GNP.

Slit film yarn is used as a jute replacement. It also finds use as carpet backing, an application which is the province of polypropylene in the U.S. HDPE film yarn demand is anticipated to increase from 34,000 to 65,000 metric tons over the 1978-1990 period. Similar growth is anticipated for HDPE fiber. This product finds primary use in rope and fishnets. HDPE pipe is a small market in Japan, with consumption estimated at only 9,000 metric tons in 1978. Growth of about 7 percent per year is forecast.

Supply

The current high density polyethylene capacity in Japan is 882,000 metric tons. A list of Japanese HDPE producers is presented in Table IV-B-3.

At present, there are no expansions in progress. However, it appears likely that capacity increases will be made since, with the growth of thin HDPE film, the effective capacity is substantially reduced and the

TABLE IV-B-3

JAPANESE HIGH DENSITY POLYETHYLENE PRODUCERS, 1978
(Thousand Metric Tons per Year)

Company	Location	Capacity
Mitsui Petrochemical	Chiba/Iwakuni	209
Showa Petrochemical	Kawasaki	176
Asahi Chemical	Mizushima	90
Mitsubishi Chemical	Mizushima	88
Nisseki Resin Chemical	Kawasaki	87
Chubu Chemical	Yokkaichi	63
Idemitsu Petrochemical	Chiba	60
Nissan Chemical	Chiba	49
Chisso	Chiba	40
Mitsubishi Petrochemical	Yokkaichi	20
		882

producers are currently operating at about capacity. By 1985, it is anticipated that capacity will be expanded by at least 100,000 metric tons per year.

Supply/Demand Situation

The potential supply/demand balance for HDPE in Japan is presented in Table IV-B-4. Basically, Japan is anticipated to be in a relatively tight situation on HDPE.

TABLE IV-B-4

POTENTIAL SUPPLY/DEMAND BALANCE FOR HIGH DENSITY POLYETHYLENE IN JAPAN
(Thousand Metric Tons)

	1977	1978	1980	1985	1990
Potential supply*	750	750	750	835	835
Forecast demand	502	614	680	880	1,060
Surplus/(deficit)	248	136	70	(45)	(225)
Actual production	496	647			
Operating rate, %	56	73			

* 85 percent of nameplate capacity.

Pricing

The prices for HDPE were 210 yen per kilo (43.4 cents per pound) in late June 1979. Additional increases are anticipated in view of rising costs. The import duty on HDPE is 28 yen per kilo.

b. Korea

Demand

The demand for high density polyethylene in Korea is anticipated to increase from 36,000 metric tons in 1977 and 60,000 metric tons in 1978 to 85,000, 140,000 and 205,000 metric tons in 1980, 1985 and 1990, respectively. Rope, fishnets and flat yarn are the major products produced, but production of film and blow molded articles will grow rapidly over the study period.

Supply

Korea Petrochemical Industry Company (50 percent Korean interests/50 percent Chisso, Marubeni), the sole producer of high density polyethylene in Korea, has a nominal capacity of 35,000 metric tons per year in a facility at Ulsan. Amoco technology is used. In 1978, production from the unit was about 33,000 metric tons. Completion of the Korea Oil ethylene expansion in 1978 has allowed the facility to operate at near capacity levels. A 70,000 metric ton per year facility is being constructed by Honan Ethylene (Korean government) and Mitsui; this should be on-stream in 1980. The unit is part of the Yeosu project.

Supply/Demand Situation

The supply/demand situation for HDPE is presented in Table IV-B-5. With completion of the Yeosu plant, Korea is anticipated to have ample supply for this product only during the early 1980s, at which time it will probably again become an importer.

TABLE IV-B-5

POTENTIAL SUPPLY/DEMAND BALANCE FOR HIGH DENSITY POLYETHYLENE IN KOREA
(Thousand Metric Tons)

	1977	1978	1980	1985	1990
Potential supply	35	35	105	105	105
Forecast demand	36	60	85	140	205
Surplus/(deficit)	(1)	(25)	20	(35)	(100)

c. Taiwan

Demand

The demand for high density polyethylene in Taiwan is anticipated to increase from 35,000 metric tons in 1977 and 45,000 metric tons in 1978 to 58,000, 80,000 and 115,000 metric tons in 1980, 1985 and 1990, respectively. Rope and yarn, blow molding and film are the major markets.

Supply

The sole HDPE producer in Taiwan is United Polymer, a joint venture of USI, Solvay and China Development. The firm operates a single 50,000 metric ton per year plant at Toufen. This plant was expanded by 14,000 metric tons in 1978 and it is unlikely to be further expanded due to ethylene limitations at the site.

Formosa Plastics will build a 120,000 metric ton per year HDPE plant as part of Taiwan's fourth petrochemical complex planned at Lin Yuan. Start-up is expected in 1982.

Supply/Demand Situation

The supply/demand situation for HDPE in Taiwan is presented in Table IV-B-6. Taiwan will be an importer of HDPE for the next few years, but the new plant will meet growing demand.

TABLE IV-B-6

POTENTIAL SUPPLY/DEMAND BALANCE FOR HIGH DENSITY POLYETHYLENE IN TAIWAN
(Thousand Metric Tons)

	1977	1978	1980	1985	1990
Potential supply*	32	45	45	153	153
Forecast demand	35	45	58	80	115
Surplus/(deficit)	(3)	0	(13)	73	38
Actual production	29	34			

* Production at 90 percent of nameplate capacity.

d. Hong Kong

The demand for high density polyethylene in Hong Kong is forecast to increase from 30,000 to 63,000 metric tons over the 1978-1990 period as is shown in Table IV-B-7. The product is utilized mainly in the production of injection and blow molding articles, which are both used domestically and exported. However, part of the growth is anticipated to result from thin film applications. In 1978, Japan and the U.S. were the major sources of HDPE resin for Hong Kong.

TABLE IV-B-7

HONG KONG HIGH DENSITY POLYETHYLENE DEMAND
(Metric Tons)

1977	25,000
1978	30,000
1980	36,000
1985	48,000
1990	63,000
AAGR, % (Base 1978)	6.4

There are no high density polyethylene facilities in Hong Kong and none are expected over the study period.

e. ASEAN Countries

The HDPE demand in the ASEAN countries is anticipated to increase from 102,800 and 114,800 metric tons in 1977 and 1978 to 297,000 metric tons

in 1990, as shown in Table IV-B-8. The use pattern for HDPE varies from country to country. Injection and blow molding are the major uses in Malaysia, Thailand and Indonesia, film predominates in Singapore, and rope and fishnets are important in the Philippines.

At present, there are no production facilities within the region, but by 1985, capacity will be 80,000 metric tons per year when the facility in Singapore is brought on stream. In addition, a 50,000 metric ton per year facility based on imported ethylene, in which USI Far East would have an interest, is planned for Thailand. However, during the 1980s a deficit situation will persist.

TABLE IV-B-8

ASEAN COUNTRY HIGH DENSITY POLYETHYLENE DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (Base 1978)
Philippines	22	25	30	45	65	9.4
Singapore	6.8	8.8	10	13	17	5.6
Malaysia	16	18	23	34	45	7.9
Thailand	16	17	22	38	60	11.1
Indonesia	42	46	54	78	110	7.5
	102.8	114.8	139	208	297	8.2

f. People's Republic of China

At present, the PRC has HDPE facilities with a capacity of about 120,000 metric tons per year. It is anticipated that imports will remain relatively modest.

3. Conclusions

Opportunities for an Alaskan Plant

The supply and demand for HDPE on the West Coast and in the Pacific Basin are summarized in Table IV-B-9.

TABLE IV-B-9

HIGH DENSITY POLYETHYENE

	Demand				Capacity, per year	
	1978	1985	1990	AAGR, %	1978	Future
	(Million Pounds)					
West Coast	500	1,065	1,610	10.3	0	0
	(Thousand Metric Tons)					
Japan	438	780	970	7.0	882	982*
Korea	60	140	205	10.1	35	105
Taiwan	45	80	115	8.1	50	170
Hong Kong	30	48	63	6.4	0	0
ASEAN Countries	115	208	297	8.2	0	80**

* Future projects not certain.
** Additional facilities possible.

It is anticipated that during the 1980s new grass-roots high density facilities will have to be at least 250 million pounds per year in size in order to be competitive. Due to the significant position of at least six firms, it is anticipated that a firm with Alaskan production could reasonably expect to capture only about 20-25 percent of the merchant market on the West Coast. This would equate to 180-225 million pounds. By 1990, with normal demand increases, sales should grow to over 300 million pounds. Any anticipated captive consumption within the region must be added to these figures.

In the mid-1980s, Korea, Hong Kong and the ASEAN countries will be major importers, with current demand totaling 450-500 million pounds. At best, about half of this current demand could be met by facilities in Japan and Taiwan since, with the trend to increased film and large container consumption, the effective capacity of HDPE units is reduced. An Alaskan facility would be well located to capture part of this current demand. In addition, Japanese producers could opt to place new HDPE capacity offshore in lieu of modernizing older plants and erecting new ones. Imports in the 200 million pound per year range would not be unreasonable.

Production of HDPE in Alaska is viable from a standpoint of market size and trends. Facilities in the 250-400 million pound per year range could be justified.

C. Polystyrene

1. West Coast Market

a. Demand

In 1978, the U.S. West Coast demand for polystyrene, including expandable beads, was estimated at 540 million pounds, or 15 percent of the total U.S. market of about 3.6 billion pounds. This 540 million pound Western U.S. market is made up of 480 million pounds of general-purpose and impact polystyrene and 60 million pounds of expandable beads. By 1990, total polystyrene demand is expected to reach 1,030 million pounds, an average annual growth rate of 5.5 percent over the 1978-1990 period, as shown in Table IV-C-1. Western Canadian consumption of about 15 million pounds in 1978 is expected to double over the period. Molding accounts for 45 percent of total polystyrene consumption. Nearly every molder in the West Coast region uses some polystyrene for proprietary products, housewares, electrical goods, toys or sporting equipment. Extrusion of polystyrene, including foamed sheet and regular film and sheet, accounted for somewhat over 30 percent of the polystyrene consumed during 1978. Foam and foamable materials, primarily expandable beads, accounted for about 20 percent.

TABLE IV-C-1

WEST COAST POLYSTYRENE DEMAND, 1978-1990
(Million Pounds)

Western U.S.	1978	1980	1985	1990	AAGR, % (1978-1990)
Molding	235	250	300	350	3.4
Extrusion	170	195	285	390	7.2
Foam and foamable materials	105	120	170	220	6.3
All other uses	30	35	50	70	7.3
Total Western U.S.	540	600	805	1,030	5.5
Western Canada	15	20	25	30	5.9
Total	555	620	830	1,060	5.5

Molding accounted for nearly 45 percent of the U.S. West Coast polystyrene consumption in 1978. Major markets were packaging, housewares, electrical and electronic applications, cassettes, toys, nursery tubs and containers. Typical of the molders is Amoco in La Mirada, CA. Amoco is a major producer of cups. High-impact polystyrene is molded by toymakers such as Mattel, Revell and Cox. In addition, Adams Brothers Plastic molds for Sears, Ideal and Tomy, a Japanese toy company. In housewares, Triplastics is a major molder of polystyrene. Another significant market for polystyrene is tape cassettes, which are produced by M.U. Engineering and UPM.

Extrusion of solid polystyrene sheet, shapes and profiles is widespread, accounting for about 30 percent of total polystyrene use. A prominent extruder is Gage Industries of Oregon, which produces sheet for thermoforming and also carries out thermoforming and vacuum forming of polystyrene. Most of Gage's output is used for packaging. Container Corporation and American Can thermoform high-impact polystyrene for hot drink cups.

About 20 ercent of the polystyrene market is comprised of foamed material either from expandable polystyrene beads (EPS) or foamed general-purpose material. There are about 20 significant processors of EPS beads in the West Coast region, including Dew Foam, Handi-Kup, W.D. Adam, K&B Mfg. and Thompson Industries, a subsidiary of Dart Industries located in Phoenix, AZ.

There are about ten producers of extruded foam sheet and molded board for insulation and other uses. A substantial portion of the total market is devoted to egg cartons by Dolco, Keyes and Packaging Corporation of America. Dow also makes foamed sheet in Torrance, CA.

Approximately 5 percent of the total polystyrene consumption is in the "other" category. This includes material for signs and material used in paper coating.

The polystyrene market in Western Canada was about 15 million pounds in 1978 and is anticipated to grow at nearly 6 percent per year and reach 30 million pounds by 1990. Foam products and molded articles are significant in the area. Significant polystyrene consumers include Gulf Plastics in Langley (foam packaging), Scott Plastics in Victoria (custom molding) and Plasti-Fab in Vancouver (foam insulation).

b. Supply

There are six producers of polystyrene on the U.S. West Coast, with a total capacity of 480 million pounds per year, as shown in Table IV-C-2. Two expansions, which will increase capacity by 70 million pounds per year, have been announced. Dow, Monsanto, Amoco and Cosden are among the major suppliers to the West Coast market.

TABLE IV-C-2

U.S. WEST COAST POLYSTYRENE PRODUCERS, 1978
(Million Pounds per Year)

Company	Location	Capacity	Expansions
A&E Plastik Pak	City of Industry, CA	45	
Amoco Chemical	Torrance, CA	65	
Cosden	Orange, CA	75	
Mobil	Santa Ana, CA	30	50
Dow Chemical	Torrance, CA	215	
Monsanto	Long Beach, CA	50	
Plastic Products	Los Angeles, CA		20
Total		480	70

There are no polystyrene producers in Western Canada. However, BASF, Dow, Monsanto and Polysar supply product from Eastern Canada. In addition, there are imports from U.S. producers.

c. Captive Market

About 20 percent, or 110 million pounds, of the polystyrene market is captive. Dow, A&E Plastik, Amoco and Mobil have captive operations within the region.

There is no captive consumption in Western Canada.

d. Pricing

Polystyrene is sold on a delivered basis in the Western U.S., with prices for the general-purpose and high-impact grades being 41 and 42 cents per pound, respectively, as of October 1, 1979. Prices have risen recently due to the styrene price increases caused by a tight benzene situation worldwide.

In Canada, general purpose polystyrene was priced at $0.526 (Canadian) per pound for general-purpose grade, with the high-impact grade moving for about 1 cent per pound more. Canadian prices should remain about the same or slightly above U.S. prices. Imports of polystyrene into Canada are subject to a 10 percent ad valorem duty.

2. Pacific Basin Market

a. Japan

Demand

Domestic demand for polystyrene in Japan is anticipated to increase from 530,000 to 1,030,000 metric tons during the 1978-1990 period. This represents a growth of 5.1 percent per year over the study period. Net polystyrene exports are currently about 60,000 metric tons, and they are anticipated to increase somewhat over the study period. The Japanese polystyrene demand by end-use is presented in Table IV-C-3.

TABLE IV-C-3

JAPANESE POLYSTYRENE DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
General-purpose and high-impact						
Electrical appliances	110	115	130	175	230	6.0
Mechanical appliances	12	13	15	20	25	5.6
Industrial goods	16	18	20	25	30	4.4
Packaging	145	160	175	215	260	4.1
Consumer items	100	110	125	170	220	5.9
Foam	147	154	175	220	265	4.6
Domestic demand	530	570	640	825	1,030	5.1
Exports	60	60	65	75	80	
	590	630	705	900	1,110	4.8

Electrical and electronics applications are anticipated to be a fast growing area for polystyrene, with demand increasing at about 6.0 percent per year over the study period. This figure reflects a slowing down of growth due to export of some consumer electronics activities to other countries and increasing difficulties in obtaining a larger share of the U.S. market. In 1977 and 1978, Japanese television manufacturers voluntarily curtailed shipments to the U.S., reducing polystyrene demand in that application. Use in nonelectric appliances and industrial goods is expected to remain small. Demand growth in the packaging, consumer items and foam (also largely packaging and consumer) categories is anticipated to rise at somewhat slower rates due to conservation efforts.

Supply

The current capacity of Japanese polystyrene producers is 739,000 metric tons, as shown in Table IV-C-4. At present, no expansions are in

progress. However, it is anticipated that additional expansions will be made in the early 1980s, primarily by firms such as Asahi-Dow, Shin Nippon Steel Chemical, Toyo Polystyrene and Mitsubishi Monsanto, which are either basic in styrene or have strong positions in the industry, coupled with styrene supplies through related companies.

TABLE IV-C-4

JAPANESE POLYSTYRENE PRODUCERS, 1978
(Thousand Metric Tons per Year)

Company	Location	Capacity
Asahi-Dow	Kawasaki	59
	Mizushima	135
	Chiba	50
Denki Kagaku	Chiba	70
Dainippon Ink	Chiba	14
	Yokkaichi	30
Idemitsu	Tokuyama	60
Mitsubishi Monsanto	Yokkaichi	91
	Kashima	24
Nippon Polystyrene	Kawasaki	52
Shin Nippon Steel Chemical	Tobata	60
Toyo Polystyrene	Kawasaki	60
	Sakai	34
		739

Supply/Demand Situation

The potential supply/demand situation for polystyrene in Japan is presented in Table IV-C-5. Basically, the existing Japanese polystyrene capacity is insufficient to meet demand beyond the early 1980s. However, it is anticipated that demand growth will be met by new facilities in Japan, and it is highly unlikely that significant polystyrene imports can be made from the U.S. except under extraordinary circumstances. For exports to Japan, a U.S. producer would be competing against other regional producers, such as Dow in Hong Kong, which have the advantage of not having to pay a tariff since Hong Kong is a "developing nation".

TABLE IV-C-5

POTENTIAL SUPPLY/DEMAND BALANCE FOR POLYSTYRENE IN JAPAN
(Thousand Metric Tons)

	1977	1978	1980	1985	1990
Potential supply*	739	739	739	739	739
Forecast demand	590	630	705	900	1,110
Surplus/(deficit)	149	109	34	(161)	(371)

* 100 percent of nameplate capacity.

Pricing

In June 1979, the Japanese price for general-purpose polystyrene was 40 yen per kilo (43.4 cents per pound). The duty on polystyrene resin is 14 percent, with the exception of the foam resin, which has a duty of 8 percent.

b. Korea

Demand for polystyrene in Korea is anticipated to increase from 48,000 metric tons in 1977 and 70,000 metric tons in 1978 to 85,000, 125,000 and 165,000 metric tons in 1980, 1985 and 1990, respectively. This represents an average annual growth of 7.4 percent from 1978. Consumption is primarily in general-purpose injection-molding grades. Demand for high-impact material for refrigerator door liners and other more demanding applications was met through imports.

Han Nam Chemical, a joint venture of Asahi-Dow and Korean interests, is the sole Korean producer with a 50,000 metric ton per year unit at Ulsan. Polystyrene imports were 17,000 metric tons in 1978. An additional 68,000 metric tons of capacity should come on stream in 1982-1983 as part of the new petrochemical complex at Yochon. It is expected that Korea will try to remain basically self-sufficient in the product, importing only those specialized grades not produced domestically.

c. Taiwan

Demand for polystyrene in Taiwan was increased from about 42,000 metric tons in 1977 to about 58,000 metric tons in 1978. Consumption exists primarily in the general-purpose injection-molding grades, although high-impact and expandable polystyrene are also utilized. Consumption is anticipated to reach 80,000 metric tons by 1980, due in part to growth in electronics and appliance sectors. By 1985 and 1990, demand is estimated to reach 110,000 and 135,000 metric tons, respectively. This represents an average annual growth of 7.3 percent over the 1978 to 1990 study period.

Taiwan has several small polystyrene producers; they have a total capacity of 69,800 metric tons per year, as shown in Table IV-C-6. In 1978, Taiwan was a net importer of about 6,000 metric tons of resin. It is anticipated that Taiwan will basically remain a small net importer of polystyrene over the study period.

TABLE IV-C-6

TAIWANESE POLYSTYRENE PRODUCERS, 1978
(Thousand Metric Tons per Year)

Company	
Poly	31.2
Taita	19.2
Shing-chi	2.4
Kao-fu	9.6
Others	7.4
	69.8

d. Hong Kong

The demand for polystyrene in Hong Kong in 1978 was roughly 100,000 metric tons. About 60-65 percent of this market consists of general-purpose resins. This market is anticipated to have reasonable growth due to expansion of the electronics industry, which utilizes

polystyrene components. Demand is anticipated to reach 120,000, 170,000 and 220,000 metric tons in 1980, 1985 and 1990, respectively. This represents an average annual growth of 6.8 percent.

Dow is the sole Hong Kong polystyrene producer with a 65,000 metric tons per year plant which came on stream in 1976. This plant supplies both local and export markets. Dow is planning to increase the capacity of this facility to 125,000 metric tons per year.

Since there is no tariff protection in Hong Kong, considerable polystyrene imports will continue throughout the study period. Imports were 75,000 metric tons in 1978. Due to the Dow plant expansion, they are expected to decrease in the early 1980s, but then increase to about 80,000 metric tons by 1985.

e. ASEAN Countries

Unlike the polyolefins, which are utilized in overwrap, bags and relatively unsophisticated applications, polystyrene finds use in electronics, appliances and more sophisticated packaging applications. As a result, it is generally the last of the major thermoplastic resins to achieve significant usage, and for this reason consumption in the ASEAN countries was only 53,000 metric tons in 1978, which is half of the consumption in Hong Kong, which only has 2 percent of the population of the ASEAN countries.

Polystyrene demand in the ASEAN countries is anticipated to increase from 42,200 and 53,600 metric tons in 1977 and 1978 to 70,000, 110,000 and 162,000 metric tons in 1980, 1985 and 1990, respectively, as shown in Table IV-C-7. Imports to the region were about 24,000 and 22,000 metric tons in 1977 and 1978. In spite of the increased production at the new Dow plant, imports are expected to increase to 45,000 metric tons by 1985 if no new capacity is introduced.

TABLE IV-C-7

ASEAN COUNTRY POLYSTYRENE DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (1978 Basis)
Philippines	9	13	15	20	29	6.9
Singapore	12.8	15.1	22.6	33	46	9.7
Malaysia	3.4	4	6	10	15	11.6
Thailand	7.7	9	11	22	34	11.7
Indonesia	9.3	12.5	15.4	25	38	9.7
	42.2	53.6	70.0	110	212	12.1

f. People's Republic of China

Polystyrene production in the PRC is quite small, with production capacity reported at only 5,000 metric tons per year. Various polystyrene grades are imported, but significant growth in polystyrene consumption will be slow in developing for the next few years, and at that time the PRC should be in a position to manufacture most of its needs domestically.

3. Conclusions

Opportunities for an Alaskan Plant

The supply and demand for polystyrene on the U.S. West Coast and in the Pacific Basin are summarized in Table IV-C-8.

During the 1980s, it is anticipated that a new grass-roots polystyrene facility, producing both general-purpose and high-impact material, will have to be about 200 million pounds per year. A new polystyrene producer could expect to capture only about 15 percent of the U.S. West Coast merchant market, or about 100 million pounds in 1985.

TABLE IV-C-8

POLYSTYRENE

	Demand				Capacity, per year	
	1978	1985	1990	AAGR, %	1978	Future
		(Million Pounds)				
West Coast	555	830	1,060	5.5	480	550*
		(Thousand Metric Tons)				
Japan	570	825	1,030	5.1	739	739*
Korea	70	125	165	7.4	50	118*
Taiwan	58	110	135	7.3	70	70*
Hong Kong	100	170	220	6.8	65	125
ASEAN Countries	54	110	212	10.6	39	47*

* Additional expansions likely.

Most Pacific Basin countries are anticipated to be virtually self-sufficient in polystyrene. Due to the entrenched positions of Dow and the affiliates of Japanese companies in the Pacific Basin, polystyrene imports from facilities outside of the region are estimated at only 100-200 million pounds in 1985. As a result, shipments from a new Alaskan producer to the region probably would not exceed 20-30 million pounds per year. Basically, production of polystyrene in Alaska by a new producer does not look too attractive from a market standpoint, since it would generally be preferable to produce the polystyrene resin close to the point of consumption.

D. Polyvinyl Chloride

1. West Coast Market

a. Demand

The U.S. West Coast region consumed an estimated 680 million pounds of polyvinyl chloride resin in 1978. This accounted for about 12 percent of the U.S. domestic consumption of 5.5 billion pounds of PVC. By 1990, West Coast demand is expected to reach 1.9 billion pounds, representing an average annual growth rate of 8.7 percent over the period. The Western Canadian market was about 15 million pounds in 1978 and it is expected to reach 40 million pounds by 1990. The demand for PVC on the West Coast is shown in Table IV-D-1.

Over 70 percent of the regional demand in 1978 was used in extrusion, particularly pipe. Molding and calendering were the other significant markets for PVC, accounting for 12 and 9 percent of the market, respectively.

Calendering markets are traditionally divided into flooring, textile and others, which includes film and sheet. There is little textile-oriented manufacture in the U.S. West Coast region, so PVC consumption in this market is negligible. However, there is considerable activity in flooring, with the major product being vinyl asbestos tile. Five of the national flooring companies are active in the West Coast area: Armstrong, Nafer (National Flooring), Flintkote, Kentile and American Biltrite. Flooring is expected to show growth significantly higher than overall U.S. growth due to new construction in the region.

Consumption of PVC resin in film and sheet was about 30 million pounds in 1978. Growth of the market is forecast at 7-9 percent per year over the 1978-1990 period. This use area is somewhat small, since there is no

TABLE IV-D-1

WEST COAST POLYVINYL CHLORIDE DEMAND
(Million Pounds)

Western U.S.	1978	1980	1985	1990	AAGR, % (1978-1990)
Calendering					
Flooring	30	35	-	-	-
Textile	*	*	-	-	-
Other, including film and sheet	30	35	-	-	-
Subtotal	60	70	105	150	8.0
Coating					
Flooring	*	*	-	-	-
Textile and paper	*	*	-	-	-
Protective coatings	10	10	-	-	-
Adhesives and other	5	10	-	-	-
Subtotal	15	20	30	40	8.5
Extrusion					
Wire and cable	25	30	-	-	-
Film and sheet	15	20	-	-	-
Rigid pipe and tube	430	545	-	-	-
All other extrusion	20	25	-	-	-
Subtotal	490	620	960	1,370	9.0
Molding					
Bottles	5	10	-	-	-
Sound records	35	40	-	-	-
Fittings for pipe	25	30	-	-	-
Other molding	15	20	-	-	-
Subtotal	80	100	150	220	8.8
All other uses	35	40	55	70	6.0
Total Western U.S.	680	850	1,300	1,850	8.7
Western Canada	15	20	30	40	8.5
Total	695	870	1,330	1,890	8.7

* Small.

production for the auto industry. The 6 calenders in the West Coast region are operated by Columbus Coated Fabrics (Borden), Ellay Plastics (W.R. Grace) and Maclin.

Coating applications for PVC on the U.S. West Coast are small, accounting for only 15 million of the 500 million pound U.S. market in 1978. No significant usage in the flooring, textile and paper areas was found.

This is because the textile industry is small in the region and paper coating is a relatively small consumer of resin. In the protective coatings area, some PVC is used for solution vinyl. Adhesives uses were also small, consuming about 5 million pounds per year. The total coating category is expected to grow to 40 million pounds by 1990.

Extrusion applications constitute the largest market for PVC resins in the U.S. West Coast region, accounting for over 70 percent of resin consumption. Of the total market of 490 million pounds of PVC in 1978, 430 million pounds were consumed in rigid pipe and tubing, mainly for irrigation and land reclamation purposes. There are about ten major producers of pipe, including Certain-Teed, Johns-Manville, Robintech, Portco, Carlon, Simpson Timber, Apache Kerone, EPPCO, Celanese, Rainbird, Richdale and Thompson. There are a number of extruders of PVC film and sheet in the Western region, including Atlas Plastics, Raum Chemical and Lustro. The products are used mainly in packaging. Wire and cable extrusion in the West involves a number of companies, including Anaconda, Carol Cable, Coaxco, Icore International, National Wire and Cable, Pacific Electricord and Whitmore. The overall market for PVC in extrusion applications is expected to reach 1,370 million pounds by 1990. This represents growth of 9 percent per year.

Other uses, including fire retardant applications, foamed PVC, roto and slush molding are estimated at 35 million pounds in 1978. Growth to 1990 is expected to average 6.0 percent per year.

Western Canada

The polyvinyl chloride market in Western Canada was about 15 million pounds in 1978 and is anticipated to grow 8-9 percent per year and reach 40 million pounds by 1990. Pipe is the largest segment of the market, with Pacific Plastics (Vancouver) and Flex-Lox (Abbotsford), being significant consumers.

b. Supply

There are three producers of polyvinyl chloride in the Western U.S. - B.F. Goodrich, Keysor Century and Stauffer. Stauffer is the only company basic in vinyl chloride monomer. Total capacity is estimated at 370 million pounds, as is shown in Table IV-D-2.

TABLE IV-D-2

U.S. WEST COAST POLYVINYL CHLORIDE PRODUCERS
(Million Pounds per Year)

Company	Location	Capacity
B.F. Goodrich Chemical	Long Beach, CA	150
Keysor Century	Saugus, CA	50
Stauffer Chemical*	Carson, CA	170
Total		370

* Has VCM production at same site.

The supply within the region is not sufficient to meet demand. Significant marketers in the region, besides the producers, are Conoco, Diamond Shamrock, Union Carbide, Borden, Tenneco, Pantasote, Ethyl and Firestone.

There are no PVC producers in Western Canada. Esso Chemical Canada and B.F. Goodrich Canada supply material from the East, and some of the U.S. producers also serve the region. It is anticipated that the Diamond Shamrock Alberta Gas Chemical joint venture will become a significant supplier in the near future when their 220 million pound per year facilities at Ft. Saskatchewan, Alberta, are completed.

c. Captive Market

Borden, which produces film, is the sole captive consumer on the U.S. West Coast. It is estimated that its consumption is about 2-3 percent of

the total demand, and no significant change in this percentage over the study period is foreseen. There are no captive consumers in Western Canada.

2. Pacific Basin Market

a. Japan

The Japanese domestic demand for polyvinyl chloride resin is forecast to increase from 1,180,000 metric tons in 1978 to 2,060,000 metric tons in 1990 (Table IV-D-3), an average annual growth of 4.6 percent. In addition, Japan has in the past been a significant net exporter of these resins, with net exports totaling 80,00 metric tons in 1977. In 1978, net exports dropped to 20,000 metric tons. This was due to the yen's appreciation, which priced Japanese PVC out of competition on world markets. Although exports are expected to again reach the 1977 level during the 1980s, they are forecast to decline as other countries in the Asian region attain greater self-sufficiency.

Rigid PVC constitutes nearly 60 percent of the Japanese market. Demand for rigid sheet, which is used in packaging applications, is anticipated to grow 6.4 percent per year. Pipe is a relatively mature product in Japan. After a sharp rise in 1978, it is expected to level off at 5 percent per year. Plasticized PVC constitutes about 30 percent of the domestic market, of which film and sheet applications constitute about half. The principal use for film is as a moisture barrier, but it is being replaced in this use by polyethylene and polypropylene. Sheet applications, such as shower curtains, are similar to these applications in the U.S. As a result, film and sheet demand is expected to grow at only about 2-3 percent per year. Use in wire and cable insulation is anticipated to follow the growth of that industry at about 4-5 percent per year. The flooring market is primarily for commercial use, since tatami and carpeting are used in residences. PVC fiber is made by Teijin for flame resistant applications and is expected to remain a specialty fiber.

TABLE IV-D-3

JAPANESE POLYVINYL CHLORIDE DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
Rigid PVC						
Sheet	155	190	215	295	400	6.4
Pipe	270	355	410	530	650	5.1
Joints	30	40	45	55	65	4.1
Rain pipe	25	30	35	45	60	5.9
Others	45	50	55	75	95	5.5
Subtotal	525	665	760	1,000	1,270	5.5
Plasticized PVC						
Film and sheet	140	165	175	200	225	2.6
Artificial leather	50	65	70	85	100	3.6
Extrusions	60	70	75	85	95	2.6
Other	55	75	80	100	130	4.6
Subtotal	305	375	400	470	550	3.2
Miscellaneous						
Wire and cable	90	103	110	135	170	4.3
Flooring	15	20	25	30	35	4.7
Fiber	7	8	10	10	10	1.9
Others	8	9	10	15	25	8.8
Subtotal	120	140	155	190	240	4.6
Total domestic demand	950	1,180	1,315	1,660	2,060	4.8
Net exports	80	20	85	70	40	-
Total demand	1,030	1,200	1,400	1,730	2,100	4.8

Supply

In Japan, the 19 producers of PVC resin have a total capacity of 1,921 metric tons, with no announced expansions at present. A number of these facilities are small and may not be able to meet more stringent environmental standards. A list of the Japanese PVC resin producers is presented in Table IV-D-4.

TABLE IV-D-4

JAPANESE POLYVINYL CHLORIDE PRODUCERS, 1978
(Thousand Metric Tons)

Company	Capacity
Asahi Glass	28
Central Chemical	25
Chisso	145
Denki Kagaku	171
Kanegafuchi	216
Kawasaki Petrochemical	30
Kureha	138
Mitsubishi Monsanto	100
Mitsui-Toatsu	117
Nippon Geon	192
Nissan Chemical	30
Ryonichi	137
Shin-Etsu	225
Sumitomo	120
Sun Arrow	64
Toa Gosei	59
Tokuyama Sekisui	49
Toyo Soda	75
	1,921

Supply/Demand Situation

The potential supply/demand balance for PVC resin in Japan is presented in Table IV-D-5. Basically, the supply from existing plants is more than sufficient to meet the overall Japanese demand until 1990, when further capacity is expected to be added.

TABLE IV-D-5

POTENTIAL SUPPLY/DEMAND BALANCE FOR POLYVINYL CHLORIDE IN JAPAN
(Thousand Metric Tons)

	1977	1978	1980	1985	1990
Potential supply*	1,921	1,921	1,921	1,921	1,921
Forecast demand	1,030	1,200	1,400	1,730	2,100
Surplus/(deficit)	891	721	521	191	(179)

* 100 percent of nameplate capacity.

Pricing

In late June 1979, prices for general-purpose PVC resins were 162 yen per kilo (33.5 cents per pound). Prices are related primarily to vinyl chloride monomer costs.

The duty on polyvinyl chloride is 8 percent ad valorem.

b. Korea

Demand

Korean PVC demand totaled about 185,000 metric tons in 1978, of which approximately 120,000 metric tons was for domestic consumption and the remainder was processed into goods for export. Overall demand is expected to reach 240,000, 350,000 and 460,000 metric tons in 1980, 1985 and 1990, respectively. This represents an average annual growth of 7.9 percent over the period. Almost all material is general-purpose grade; however, the demand for pipe resin is increasing.

The major PVC processors in Korea are Lucky, Chin Yang Chemical, Daihan, National Plastic, Sam Yung Chemical and Korea Plastic Industry. These firms account for over 60 percent of consumption.

Supply

The current PVC capacity in Korea is 200,000 metric tons per year. Paste resins make up 10,000 metric tons per year of this total. Additional facilities are anticipated during the early 1980s to meet the growing demand. The Korean PVC producers and their capacities are presented in Table IV-D-6.

TABLE V-D-6

KOREAN POLYVINYL CHLORIDE PRODUCERS
(Thousand Metric Tons)

Company	Location	Capacity
Korea Plastics Industry	Kunsan, Luchon, Ulsan, Chin Hae, Pegan	150
Lucky Ltd.	Yeochon	50
		200

Supply/Demand Situation

The potential supply/demand balance for PVC resins in Korea is presented in Table IV-D-7. Basicaily, Korea is anticipated to be in an essentially balanced situation throughout the study period, assuming that new capacity is installed to utilize the available vinyl chloride monomer. In spite of the balanced situation, there will continue to be some importation of special product grades.

TABLE IV-D-7

POTENTIAL SUPPLY/DEMAND BALANCE FOR POLYVINYL CHLORIDE IN KOREA
(Thousand Metric Tons)

	1977	1978	1980	1985	1990
Potential supply	150	200	200	350*	460*
Forecast demand	150	185	240	350	460
Surplus/(deficit)	0	15	(40)	-	-
Actual production	124	195			

* Assumes new plant capacity.

c. Taiwan

Demand

Taiwan has a well-developed PVC industry, which probably is the largest in the world in relation to the size of the country. Demand in 1978, including exports of 60,000 metric tons, is estimated at 390,000 metric tons. Domestic demand is anticipated to reach 380,000, 535,000 and

695,000 metric tons in 1980, 1985 and 1990, respectively. Resin exports are expected to remain at about current levels.

The Taiwan PVC industry has been developed to serve world markets and generally has more sophisticated equipment than most major developed nations. As a result, exports in the form of sheet and finished products are anticipated to grow strongly. Most of the PVC produced is consumed captively. Formosa Plastics, China Gulf, Ocean Plastics and Cathay are major consumers.

Supply

In 1978, the Taiwan PVC industry capacity was 428,000 metric tons, with Formosa Plastics dominating the industry. Formosa Plastics added 24,000 metric tons of capacity in 1979, increasing the current industry capacity to 452,000 metric tons. At present, there are no major expansions in progress, but supply is anticipated to keep ahead of demand. The PVC producers and their capacities are listed in Table IV-D-8.

TABLE IV-D-8

TAIWAN POLYVINYL CHLORIDE PRODUCERS, 1978

Company	Capacity
Formosa Plastics	342
China Gulf Plastics	38
Cathay	30
Ocean	18
	428

Supply/Demand Situation

The potential supply/demand balance for PVC in Taiwan is presented in Table IV-D-9. Basically, capacity is expected to be added to meet demand in the future, and it is anticipated that imports of the material will be limited to special grades and spot situations.

TABLE IV-D-9

POTENTIAL SUPPLY/DEMAND BALANCE FOR POLYVINYL CHLORIDE IN TAIWAN
(Thousand Metric Tons)

	1977	1978	1980	1985	1990
Potential supply*	385	385	500**	650**	820**
Forecast demand***	315	390	450	600	770
Surplus/(deficit)	70	(5)	50	50	50
Production	310	390			

* 90 percent of nameplate capacity.
** Assumes new facilities.
*** Demand includes resin exports.

d. Hong Kong

There is no production of PVC resin in Hong Kong, nor is any expected. The total demand for PVC resins was approximately 50,000 metric tons in 1978 and is anticipated to increase to 56,000, 73,000 and 89,000 metric tons in 1980, 1985 and 1990, respectively.

The major products made from PVC are sandals, footwear and artificial leather. In recent years, the rigid pipe market has begun to be significant. Paste resin is consumed for use in dolls. The demand growth in Hong Kong is expected to be relatively modest since the economy is almost totally committed to the export market and its strength is in the development of techniques to make new products most efficiently, rather than in the production of more and more of the same product.

e. ASEAN Countries

Polyvinyl chloride demand in the ASEAN countries is anticipated to increase from 119,400 and 134,500 metric tons in 1977 and 1978 to 315,000 metric tons in 1990, as shown in Table IV-D-10. At present, the eight PVC producers in the region provided about 120,000 metric tons of the region's needs in 1978. The producers and their capacities are listed in

Table IV-D-11. Over the study period, expansion within the region will occur, such that imports from 1985 to 1990 should amount to approximately 50,000 metric tons yearly.

TABLE IV-D-10

ASEAN COUNTRY POLYVINYL CHLORIDE DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (Base 1978)
Philippines	30	34	42	75	120	11.1
Singapore	11	12	15	20	30	7.9
Malaysia	18.4	21	28	45	70	10.6
Thailand	25	27.5	35	55	85	9.9
Indonesia	35	40	55	80	110	8.8
	119.4	134.5	175	275	415	9.8

f. People's Republic of China

The PVC market in the PRC is relatively small, and existing capacity is only about 20,000 metric tons per year. It is anticipated that Japan will continue to supply most of the modest imports of the product.

3. Conclusions

Opportunities for an Alaskan Plant

The supply and demand for PVC on the West Coast and in the Pacific Basin are summarized in Table IV-D-12.

It is anticipated that, during the 1980s, new grass-roots polyvinyl chloride facilities will have to be at least 200 million pounds per year in size in order to be competitive. Due to the highly competitive situation in PVC resins, a new West Coast producer could reasonably expect to capture only about 15 percent of the merchant market. This quantity would be sufficient to enable the facility to run essentially at capacity by 1985.

TABLE IV-D-11

ASEAN COUNTRY POLYVINYL CHLORIDE PRODUCERS
(Thousand Metric Tons Per Year)

Company	Capacity	Expansions
Philippines		
Mabuhay Vinyl	28	-
Philippine Vinyl Consortium	25	-
	53	
Singapore		
Singapore Polymer	15	-
Malaysia		
Malaysian Electro-Chemical Industries	12	-
Synthetic Resins	12	
	24	
Thailand		
Thai Plastics & Chemical	20-25	to 45 (1979) 70 (early 1980s)
Indonesia		
Eastern Polymer	15	20 (1979)
Standard Toyo Polymer	24	
	39	
Total	151-156	

TABLE IV-D-12

POLYSTYRENE

	Demand				Capacity, per year	
	1978	1985	1990	AAGR, %	1978	Future
	(Million Pounds)					
West Coast	695	1,330	1,890	8.7	370	370
	(Thousand Metric Tons)					
Japan	1,180	1,660	2,060	4.8	1,921	1,921*
Korea	185	350	460	7.9	200	200*
Taiwan	330	535	695	6.4	428	452*
Hong Kong	50	73	89	4.9	0	0
ASEAN Countries	135	275	415	8.8	151	221*

* Additional expansions likely.

Countries within the Pacific Basin are anticipated to be virtually self-sufficient in PVC. Imports required from outside the Pacific Basin countries are expected to be less than 100 million pounds in 1985, which provides very little opportunity for exports from an Alaskan plant.

Although there is the potential to supply PVC resin to the Pacific Basin countries, the nature of the PVC business generally makes it more attractive to ship vinyl chloride monomer and produce the resin near the consumption point.

AGO 559673

E. Styrene

1. West Coast Market

a. Demand

The U.S. West Coast demand for styrene is forecast to increase from 597 million pounds in 1977 and 634 million pounds in 1978 to 715, 995 and 1,330 million pounds in 1980, 1985 and 1990, respectively, as shown in Table IV-E-1. Current consumption represents about 10 percent of U.S. domestic demand. At present, polystyrene, ABS resins, styrene-butadiene latices, unsaturated polyester resins and alkyd resins are the only styrene derivatives produced within the region. Production of SBR and various low-volume styrene derivatives is not anticipated over the study period. The West Canadian demand for styrene is about 5 million pounds per year, and it should double over the study period.

TABLE IV-E-1

WEST COAST STYRENE DEMAND
(Million Pounds)

Western U.S.	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
Polystyrene	390	410	455	610	780	5.5
SBR elastomer	-	-	-	-	-	-
ABS resins	14	15	16	20	25	4.3
Styrene-butadiene latices	17	18	20	25	30	4.3
Unsaturated polyesters	130	140	166	260	390	8.9
Alkyd resins and other uses	46	51	58	80	105	6.2
Total Western U.S.	597	634	715	995	1,330	6.4
Western Canada	5	5	6	8	10	5.9
Total	602	639	721	1,003	1,340	6.4

Polystyrene is the largest application for styrene within the Western U.S. region. In 1976, about 82 percent of regional polystyrene demand was met by local production by A&E Plastik, Amoco, Cosden, Mobil, Dow and Monsanto. By 1980, locally produced material is expected to represent 80 percent of consumption; by 1985, however, the percentage should increase

to 85 percent due to the probable construction of new facilities by other producers, possibly BASF. Information on the polystyrene market is presented in Section IV-C.

SBR elastomer is not produced within the region and no production is anticipated over the study period. Dow and Union Oil produce styrene-butadiene latex. These firms have about 60 percent of the West Coast market and are expected to maintain their share of this relatively small market.

Dow Chemical, the only producer of ABS resins within the region, has a 30 million pounds per year plant at Torrance, CA. Because of the relatively small size of the ABS resin market, no new facilities are contemplated and only slow growth is anticipated in this application.

All unsaturated polyester resins utilized on the West Coast are produced within the region and, due to the nature of the product, the West Coast is expected to meet its needs with local production. Thus, styrene demand will follow regional growth in unsaturated polyester consumption. Unsaturated polyesters are produced by a number of firms within the region, as shown in Table IV-E-2.

TABLE IV-E-2

U.S. WEST COAST UNSATURATED POLYESTER RESIN PRODUCERS

Company	Location
Alpha Chemical	Perris, CA
Ashland Chemical	Los Angeles, CA
Cargill	Lynwood, CA
Glidden Durkee (SCM)	San Francisco, CA
Koppers	Richmond, CA
PPG Industries	Torrance, CA
Reichhold Chemicals	Azusa, CA
	S. San Francisco, CA
Sherwin Williams	Emeryville, CA
Synres Division of DSM	Anaheim, CA
USS Chemicals	Colton, CA
Vistron (Filon/Silmar)	Hawthorne, CA
Wittaker	Gardena, CA

Alkyd coating resins and molding compounds are produced within the region by at least a dozen firms, including Benjamin Moore, DuPont, Sherwin Williams and Synres. Demand for these products is forecast to grow at about 2.5 percent per year.

The Western Canadian region has styrene consumption for alkyd and unsaturated resin production. At present, demand is about 5 million pounds per year and is expected to double by 1990. Consumers include Bapco Paint at Surrey and Reichhold at Port Moody.

b. Supply

There are no producers of styrene in the West Coast region. Dow, Monsanto, Mobil, Cosden and Amoco have captive or pseudocaptive consumption of styrene, which is supplied from the Gulf Coast. Some of these firms and Gulf are the likely suppliers to the small alkyd and unsaturated polyester consumers. Polysar is the major styrene supplier in Western Canada.

c. Captive Market

In 1978, the captive market for styrene on the U.S. West Coast was about 365 million pounds, or 66 percent of regional demand. This percentage is expected to decrease to about 55 percent by 1985 due to the rapid growth of the unsaturated polyester resin market, which is almost entirely merchant. The captive styrene consumers are presented in Table IV-E-3. There is no captive styrene consumption in Western Canada.

TABLE IV-E-3

U.S. WEST COAST CAPTIVE STYRENE CONSUMERS

Company	Derivatives Made
Amoco	Polystyrene
Cosden	Polystyrene
Mobil	Polystyrene
Dow	Polystyrene, ABS, SB latices
Monsanto	Polystyrene
USS Chemicals	Unsaturated polyesters

d. Pricing

In the U.S., styrene is priced at 35 cents per pound, FOB works in tank cars. The Canadian price is $0.41 (Canadian) per pound FOB Sarnia. Styrene prices depend primarily on the price and availability of benzene and the market situation for styrene.

2. Pacific Basin Market

a. Japan

The Japanese demand for styrene was about 1,112,000 metric tons in 1978, including net exports of 12,000 metric tons. Domestic demand is forecast to increase to 1,215,000, 1,540,000 and 1,920,000 metric tons in 1980, 1985 and 1990, respectively, while exports are expected to decrease in 1980 due to the startup of facilities in Taiwan and Korea. The Japanese styrene demand is summarized in Table IV-E-4.

TABLE IV-E-4

JAPANESE STYRENE DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
Polystyrene	620	660	740	950	1,170	4.8
SBR elastomer and latex	135	140	145	165	185	2.3
Unsaturated polyesters	70	70	75	90	120	4.6
ABS resins	125	130	145	190	255	5.7
SAN resins	45	50	55	70	90	5.0
Others	45	50	55	75	100	5.9
Total domestic demand	1,040	1,100	1,215	1,540	1,920	4.8
Net exports	27	12	0	20	30	-
Total demand	1,067	1,112	1,215	1,560	1,950	4.8

General-purpose, high-impact and foam polystyrene constitute about 60 percent of styrene demand. Demand over the study period is anticipated to increase 4-5 percent per year. This is due to a slowdown in the growth of the electrical appliance and electronics industries as some manufacture is shifted to Korea, Taiwan and elsewhere. In addition,

polypropylene is capturing some markets traditionally held by styrene resins. Consumption in SBR elastomer and latex is anticipated to have only nominal growth. A substantial proportion of SBR is exported and the erection of similar export-oriented SBR facilities in Korea and Taiwan has reduced these exports. ABS resins, which find considerable use in the electrical and electronics industries, are also experiencing slow growth due to the inroads of polypropylene. Unsaturated polyester resins and other styrene applications also have only modest growth prospects.

Supply

The production capacity for styrene in Japan is 1,550,000 metric tons per year, as shown in Table IV-E-5. Mitsubishi Petrochemical is currently expanding by 30,000 metric tons per year, and expansions of at least 200,000 metric tons per year are expected in the early 1980s. Production in 1978 was 1,122,000 metric tons, some 10,000 metric tons above consumption for the year.

TABLE IV-E-5

JAPANESE STYRENE PRODUCERS, 1978
(Thousand Metric Tons per Year)

Company	Location	Capacity
Asahi Dow	Mizushima/Kawasaki	395
Chubu	Yokkaichi	80
Denki Kagaku	Chiba	75
Idemitsu Petrochemical	Chiba	90
Mitsubishi Petrochemical	Kashima/Yokkaichi	410
Mitsui Toatsu	Tokuyama	90
Nippon Oxirane	Chiba	225
Nippon Steel Chemical	Tobata/Ohita	85
Sumitomo Chemical	Chiba	100
		1,550

Supply/Demand Situation

The supply/demand situation for styrene in Japan is shown in Table IV-E-6. Basically, the existing supply is sufficient to meet forecast demand only until the early 1980s. However, during the 1980s, it is anticipated that the smaller, higher cost facilities will be replaced

with larger ones. Although Japan has been self-sufficient in styrene, importation of the product and/or ethylbenzene is a possibility. Japanese styrene producers view ethylbenzene imports as an opportunity to lower costs somewhat, at the same time retaining complete control over styrene manufacture and the styrene market.

Pricing

The Japanese price for styrene was 190 yen per kilo (39 cents per pound) in late June. Prices depend primarily upon benzene prices and market conditions. Styrene imports are subject to an 8 percent duty, while ethylbenzene exports are subject to a duty of only 2 percent.

TABLE IV-E-6

POTENTIAL SUPPLY/DEMAND BALANCE FOR STYRENE IN JAPAN
(Thousand Metric Tons)

	1978	1980	1985	1990
Potential supply*	1,300	1,330	1,530	1,530
Forecast demand	1,112	1,215	1,560	1,950
Surplus/(deficit)	188	105	(30)	(430)

* Estimated effective capacity.

b. Korea

The demand for styrene in Korea was 62,600 and 74,900 metric tons in 1977 and 1978, respectively. Demand is expected to reach 108,000, 167,000 and 235,000 metric tons in 1980, 1985 and 1990, respectively.

Polystyrene, SBR elastomer and unsaturated polyester resins are the major uses for the product in Korea. Almost all of the demand for these products will be met by local production. In addition, a small quantity is used for ABS production.

At present, there is one styrene producer in Korea. A 60,000 metric ton per year unit, owned by Ulsan Petrochemical at the Ulsan complex, came on stream in 1978. A second 125,000 metric ton per year unit, owned by

Chin Yang Chemical and located at the Yochon complex, is scheduled to be completed about 1983. Basically, Korea is anticipated to be self-sufficient in styrene, but the product will be imported in the early 1980s until a second unit is completed.

c. Taiwan

The demand for styrene in Taiwan is forecast to increase from 56,000 metric tons in 1977 to 107,000, 162,000 and 201,000 metric tons in 1980, 1985 and 1990, respectively. Styrene consumption for polystyrene will approximate polystyrene demand. Styrene demand for SBR should continue to grow fairly rapidly, paralleling the growth of domestic markets and tire and elastomer exports. Taiwan has a relatively high demand for unsaturated polyester resins due to the export-oriented sailboat, powerboat and yacht industry on the island. ABS resins are produced by Poly. The market for ABS resins is expected to remain relatively small.

The only styrene producer in Taiwan is Delta Petrochemical, which started production in late 1976 at Kaohsiung. The facility has a capacity of 100,000 metric tons per year. Delta will add 100,000 metric tons of styrene as part of the fourth petrochemical complex at Lin Yuan. With startup of the new unit expected in 1982, Taiwan will have excess styrene capacity until the end of the study period.

d. Hong Kong

Since Dow Chemicals' polystyrene facility is the only styrene consumer in Hong Kong, demand for the product will reflect its requirements, which are estimated as follows:

1978	74,000
1980	75,000
1985	125,000
1990	125,000

The styrene comes from Dow's U.S. and European facilities, although on occasion Asahi-Dow is the source of this material.

e. ASEAN Countries

Demand for styrene in the ASEAN countries is forecast to increase from 13,000 and 25,000 metric tons in 1977 and 1978, respectively, to 34,000 metric tons in 1980 and 125,000 metric tons in 1990, as shown in Table IV-E-7. Demand is almost entirely for polystyrene production. The demand figures for 1985 and 1990 assume additional polystyrene capacity within the region. Dow and affiliates of Japanese companies account for most of the styrene demand within the area.

TABLE IV-E-7

ASEAN COUNTRY STYRENE DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (Base 1978)
Philippines	8	12	13			
Singapore	-	-	-			
Malaysia	5	6	7			
Thailand	-	7	14			
Indonesia	-	-	-			
Total	13	25	34	75	125	14.3

At present, there are no styrene plants in the ASEAN region, and it is unlikely that a facility will be built during the study period.

f. People's Republic of China

No significant styrene imports are foreseen over the study period, since the PRC would prefer to import the modest quantity of resins required.

3. Conclusions

Opportunities for an Alaskan Plant

The supply and demand for styrene on the U.S. West Coast and in the Pacific Basin are summarized in Table IV-E-8.

TABLE IV-E-8

STYRENE

	Demand				Capacity, per year	
	1978	1985	1990	AAGR, %	1978	Future
	(Million Pounds)					
West Coast	639	1,003	1,340	6.4	0	0
	(Thousand Metric Tons)					
Japan	1,112	1,540	1,920	4.8	1,550	1,780*
Korea	75	167	235	10.0	60	185
Taiwan	81	162	201	7.9	100	200
Hong Kong	74	125	125	4.5	0	0
ASEAN Countries	25	75	125	14.3	0	0

* Additional expansions likely.

During the 1980s, it is expected that a styrene plant will have to be at least 600-800 million pounds per year in size in order to be competitive. By 1985, the U.S. West Coast will have a requirement for 1,000 million pounds of styrene, but the merchant market will only be about 500 million pounds. The output from an Alaskan plant could be disposed of in the region through exchanges, but due to the nature of the styrene market, a commitment to styrene production would also involve a major commitment to the polystyrene business elsewhere in order to move the styrene produced.

There is no opportunity for the movement of styrene to the Pacific Basin over the long term without the involvement of Dow or the Japanese, which have the captive markets.

In order to produce styrene, it would be necessary to have a source of benzene. This could be obtained from the proposed Alpetco or Alberta facilities.

F. Vinyl Chloride Monomer

1. West Coast Market

a. Demand

The U.S. West Coast demand for VCM was estimated at 335 million pounds in 1978, or 5.1 percent of the total U.S. market of 6.5 billion pounds. The only use was for polyvinyl chloride polymer (PVC) production within the region. The three PVC producers, their PVC capacity and their estimated consumption of vinyl chloride monomer are shown in Table IV-F-1. There is no vinyl chloride consumption in Western Canada.

TABLE IV-F-1

WEST COAST VINYL CHLORIDE MONOMER DEMAND
(Million Pounds)

Company	Location	PVC Capacity	Estimated VCM Demand	
			1978	1980
B.F. Goodrich	Long Beach, CA	150	150	150
Keysor Century	Saugus, CA	50	45	50
Stauffer	Carson, CA	160	140	160
Total		360	335	360

The future demand for vinyl chloride monomer on the West Coast is tied to PVC production levels in the region. By 1980, it is anticipated that the existing facilities will be operating at capacity levels due to market growth. As a result, VCM demand will reach about 360 million pounds, and it will remain at this level during the 1980s unless additional facilities are built. Since the West Coast PVC market is expected to reach 1,890 million pounds by 1990, erection of additional facilities is likely, particularly if an adequate supply of VCM exists within the region. As a result, regional VCM demand could approach 500-600 million pounds by 1985 if there were an incentive to build additional facilities.

b. Supply

Stauffer is the only producer of vinyl chloride monomer in the Western region, with a 175 million pound a year plant in Carson, CA. This facility normally operates at close to capacity and meets about half of the regional VCM needs. The remainder is brought into the region by Goodrich. The long-term viability of the Stauffer plant is questionable and it is felt that this unit and the Arco ethylene plant, which supplies it, will be shut down within the next few years.

c. Captive Market

Stauffer is estimated to have utilized 140 million pounds for captive use. Goodrich meets most of its vinyl chloride requirements with captive production, but the firm probably supplies the West Coast with purchased material. As a result, about 40 percent of the total VCM consumed in the U.S. West Coast represents captive production.

d. Pricing

The price for vinyl chloride monomer as of October 1979 was 17 cents per pound. Price levels are primarily determined by energy costs and the supply/demand situation for the product.

2. Pacific Basin Market

a. Japan

Demand

The Japanese demand for vinyl chloride monomer is forecast to increase from 1,550,000 metric tons in 1978 to 1,690,000, 2,090,000 and 2,540,000 metric tons in 1980, 1985 and 1990, respectively, as shown in Table IV-F-2. Details of the polyvinyl chloride market for VCM are provided in

Section IV-D. Other uses are as a chemical intermediate and in the production of modacrylic fibers. In 1978, Japan exported 180,000 metric tons of VCM to Far Eastern countries and Australia. Exports are anticipated to drop by 1980 due to the new facilities in Korea and Taiwan. However, they should rise in the 1980-1990 period, primarily due to increased demand in the ASEAN countries.

TABLE IV-F-2

JAPANESE VINYL CHLORIDE MONOMER DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
Polyvinyl chloride	1,080	1,260	1,470	1,810	2,200	4.8
Other uses	105	110	120	160	210	5.5
Domestic demand	1,185	1,370	1,590	1,970	2,410	4.8
Exports	165	180	100	120	130	-
Total demand	1,350	1,550	1,690	2,090	2,540	4.2
Actual production	1,340	1,505				

Supply

The current Japanese VCM capacity is 2,191,000 metric tons per year, as shown in Table IV-F-3. Since the operating factor for VCM is low, some small facilities are now on standby.

Although there are no expansions in progress at present, an additional 475,000 metric tons of capacity was announced for the early to mid-1980s. In addition, there could be replacement of smaller facilities with new, larger plants.

Supply/Demand Situation

Basically, there is enough current and planned capacity to more than meet demand throughout the study period. However, due to the chlorine/caustic imbalance there could be imports of vinyl chloride or ethylene dichloride into the country in spite of sufficient domestic capacity.

TABLE IV-F-3

JAPANESE VINYL CHLORIDE MONOMER PRODUCERS, 1978
(Thousand Metric Tons Per Year)

Company	Location	Capacity
Asahi Glass	Chiba	56
	Kashima	
Central Chemical	Kawasaki	80
Chiba Enbi Monomer	Chiba	160
Chisso	Minamata	73
Denki Kagaku	Ohmi	42
Kanagafuchi	Takasago	140
Kashima Enbi Monomer	Kashima	220
Kureha	Nishiki	150
Mitsubishi Monsanto	Yokkaichi	80
Mitsui Toatsu	Nagoya	60
	Senpoku	66
Nippon Geon	Takaoka	120
Nissan Chemical	Chiba	60
Ryonichi	Mizushima	220
Sanyo Monomer	Mizushima	150
Sun Arrow Kagaku	Tokuyama	110
Sumitomo Chemical	Niihama	55
Toi Gosei	Tokushima	50
Toyo Soda	Nanyo	170
	Yokkaichi	129
		2,191

b. Korea

The demand for VCM in Korea is expected to increase from an estimated 130,000 metric tons in 1977 and 200,000 metric tons in 1978 to 245,000, 360,000 and 470,000 metric tons in 1980, 1985 and 1990, respectively, in order to meet the production forecast for PVC. This represents an average annual growth of 7.4 percent from 1978.

The current capacity for VCM in Korea is 78,000 metric tons per year, as shown in Table IV-F-4. Capacity will increase by 150,000 metric tons per year in 1979, but the overall capacity should only be 210,000 metric tons per year since the acetylene-based units will be placed on standby. An additional facility is anticipated onstream about 1983 as part of the Yochon complex.

TABLE IV-F-4

KOREAN VINYL CHLORIDE MONOMER PRODUCERS, 1978
(Thousand Metric Tons)

Company	Capacity	Expansions	Process
Korea Plastic Industry (4 plants)	18	-	Acetylene
Korea Pacific	60	150 (1979)	Ethylene
	78	200 (1983)	
		350	

The supply/demand balance for VCM in Korea is presented in Table IV-F-5. The local industry operates, when possible, essentially at capacity, with imports filling the remainder of the demand. After completion of the new VCM plants, Korea will have excess capacity. It is anticipated that this material will be exported in the form of both VCM and ethylene dichloride to Australia and other Far Eastern nations.

TABLE IV-F-5

POTENTIAL SUPPLY/DEMAND BALANCE FOR VINYL CHLORIDE MONOMER IN KOREA
(Thousand Metric Tons)

	1977	1978	1980	1985	1990
Potential supply	78	78	230	410	410
Forecast demand	130	200	245	360	470
Surplus/(deficit)	(52)	(122)	(15)	50	(60)
Actual production	73	65			

c. Taiwan

The demand for VCM is anticipated to increase from about 320,000 metric tons in 1977 and 400,000 metric tons in 1978 to 460,000, 615,000 and 785,000 metric tons in 1980, 1985 and 1990, respectively, in order to meet the PVC resin production forecast. This represents an average annual growth of 5.8 percent from 1978. VCM exports are expected to be small.

The capacity for VCM production in Taiwan is estimated at 360,000 metric tons per year, as shown in Table IV-F-6.

TABLE IV-F-6

TAIWAN VINYL CHLORIDE MONOMER PRODUCERS, 1978
(Thousand Metric Tons)

	Capacity
Formosa Plastics	240
Taiwan VCM	120
	360

In 1978, Taiwan produced about 330,000 metric tons of VCM and imported 70,000 metric tons. VCM capacity in Taiwan is expected to increase to meet forecast demand throughout the study period. A significant part of the additional needs will be met through ethylene dichloride imports.

d. Hong Kong

There is no PVC production in Hong Kong nor is any expected throughout the study period. As a result, there is no anticipated requirement for VCM.

e. ASEAN Countries

ASEAN countries' VCM demand is forecast to increase from 108,000 and 120,000 metric tons in 1977 and 1978, to an estimated 149,000, 235,000 and 365,000 metric tons in 1980, 1985 and 1990, respectively, as shown in Table IV-F-7. These demand forecasts take into account anticipated increased production within the region from facilities which would be built in the 1980-1990 period.

TABLE IV-F-7

ASEAN COUNTRY VINYL CHLORIDE MONOMER DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (Base 1978)
Philippines	27	31	42	70	115	11.5
Singapore	15	15	15	15	15	-
Malaysia	18	20	24	40	65	10.3
Thailand	24	27	33	50	75	8.9
Indonesia	24	27	35	60	95	11.1
Total	108	120	149	235	365	9.7

At present, there is no supply of VCM within the ASEAN countries.

f. People's Republic of China

Vinyl chloride imports into the PRC are insignificant in relation to a world-scale plant and, as such, were not considered.

3. Conclusions

Opportunities for an Alaskan Plant

The supply and demand of vinyl chloride monomer on the West Coast and in the Pacific Basin are summarized in Table IV-F-8.

TABLE IV-F-8

VINYL CHLORIDE MONOMER

	Demand*				Capacity, per year	
	1978	1985	1990	AAGR, %	1978	Future
	(Million Pounds)					
West Coast	335	500-600	500-600	-	175	175**
	(Thousand Metric Tons)					
Japan	1,370	1,970	2,410	4.8	2,191	2,191
Korea	200	360	470	7.4	78	410
Taiwan	400	615	785	5.8	360	700
Hong Kong	0	0	0	0	0	0
ASEAN Countries	120	235	365	9.7	0	0

* In part dependent upon new PVC facilities.
** Plant may shut down.

Vinyl chloride monomer consumption on the West Coast was about 335 million pounds in 1978, and it could conceivably reach 500-600 million pounds by 1985 if there were a large-scale availability of material within the region. All of this material would have to be supplied by a new producer, since the existing Stauffer plant is expected to be shut down within the new few years.

The ASEAN countries are expected to be major VCM importers through the study period. In addition, both Japan and Taiwan have severe chlorine/caustic soda imbalances and thus could be substantial importers of vinyl chloride and/or ethylene dichloride in spite of adequate domestic capacity.

The production of vinyl chloride monomer and/or ethylene dichloride in Alaska would entail producing or bringing chlorine into the plant site. In the future, it is anticipated that the West Coast area could support an 800 million to 1 billion pound per year VCM plant without causing a surplus of caustic soda in the region.

AGO 559690

G. Ethylene Glycol

1. West Coast Market

a. Demand

The U.S. West Coast demand for ethylene glycol was 200 million pounds in 1977 and 185 million pounds in 1978. Essentially all was used in antifreeze manufacture. By 1990, ethylene glycol demand is expected to be 230 million pounds, a 1.8 percent average annual growth rate over the period, as shown in Table IV-G-1. The Western Canadian ethylene glycol market was about 15 million pounds in 1978, and only nominal growth is forecast.

TABLE IV-G-1

WEST COAST ETHYLENE GLYCOL DEMAND
(Million Pounds)

Western U.S.	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
Antifreeze	197	182	191	210	224	1.7
Polyester fiber	-	-	-	-	-	-
Polyester film	-	-	-	-	-	-
Other	3	3	4	5	6	-
Total Western U.S.	200	185	195	215	230	1.8
Western Canada	15	15	16	17	18	1.5
Total	215	200	211	232	248	1.8

The U.S. West Coast accounts for only about 5 percent of the ethylene glycol market, since there is no consumption for polyester fiber and film within the region.

About 10 percent of U.S. antifreeze consumption is on the West Coast. This market is forecast to grow slowly due to saturation of the automobile market and decreasing cooling system size. Most antifreeze is sold as branched products. The remaining consumption is in specialty applications such as in latex paints.

The Canadian ethylene glycol market is utilized almost entirely for antifreeze. Minor amounts are used in paints.

b. Supply

There are no production facilities on the West Coast. All ethylene glycol is shipped into the region. Union Carbide and Dow are the major suppliers to the U.S. West Coast. Other suppliers include PPG, BASF-Wyandotte, Texas and Northern Petrochemical. Most of the Canadian market is also supplied by Union Carbide and Dow.

c. Captive Market

Approximately 60-70 percent of the West Coast market for ethylene glycol is represented by the national antifreeze brands of the ethylene glycol manufacturers and by the petroleum companies with a captive ethylene glycol source.

Although the antifreeze is merchanted, the consumer is purchasing a branded item, so this market is really not available to an independent ethylene glcyol producer. It is anticipated that the percentage of the market attained by firms with a captive ethylene glycol source will increase by 5-10 percent over the study period, following a national trend.

d. Pricing

The U.S. ethylene glycol price is 28 cents per pound, while the Canadian price is $0.35 (Canadian) per pound at producing locations. Glycol prices are primarily related to ethylene costs and market conditions. Ethylene glycol imports into Canada are subject to a 10 percent ad valorem duty.

2. Pacific Basin Market

a. Japan

In Japan, the situation for ethylene glycol is related to the overall ethylene oxide picture. The demand for ethylene oxide in Japan (Table IV-G-2) depends largely upon the production of ethylene glycol to meet both domestic and export needs. Demand is anticipated to grow 6.0 percent per year during the 1977-1990 period, primarily to meet increases in domestic textile consumption. Textile exports are anticipated to remain static or decline, while fiber exports are expected to show only modest growth, with an increasing percentage of exports consisting of the more specialized grades. Demand growth in the post-1980 period is anticipated at about 3 percent per year due to saturation of domestic markets and a declining export market.

Polyester film is used in x-ray, photographic, fiber, and audio and video tapes. Antifreeze sales are tied to domestic vehicle registrations and export sales of vehicles and will also be enhanced by the trend to the production of somewhat larger vehicles. The industrial markets for ethylene glycol and the higher glycols are forecast to grow at about 5 percent per year.

Ethylene glycol net exports were 200,000 metric tons in 1978. A substantial decline is anticipated by 1980, primarily because of the start-up of new glycol plants in Taiwan and Korea.

Other uses for ethylene glycol include surfactants, ethanolamines, glycol ethers and other derivatives. Growth in the 4-5 percent per year range is anticipated.

Overall demand for ethylene oxide was 538,000 metric tons in 1977 and 631,000 metric tons in 1978. Demand is forecast to reach 615,000, 775,000 and 925,000 metric tons in 1980, 1985 and 1990, respectively. This represents an average annual growth rate of 3.2 percent during the 1978-1990 period.

TABLE IV-G-2

JAPANESE ETHYLENE OXIDE/GLYCOL DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
Ethylene glycol						
Polyester fiber	210	235	250	310	340	3.1
Polyester film	12	13	15	20	25	5.6
Polyethylene terephthalate resin	1	3	5	15	20	17.1
Antifreeze	40	43	50	65	80	5.3
Others, individual higher glycols	110	116	130	165	210	5.0
Total domestic demand	373	410	450	575	675	4.2
Net exports	195	200	130	145	165	-
Total demand	568	610	580	720	840	2.7
Inventory change	(45)	20	-	-	-	-
Ethylene glycol production	523	630	580	720	840	2.4
Ethylene oxide						
Ethylene glycol	382	473	435	540	630	2.4
Other uses	156	158	180	235	295	5.3
Total demand	538	631	615	775	925	3.2

Supply

The current ethylene oxide capacity in Japan is 635,000 metric tons per year. Capacity should increase by 120,000 metric tons per year in the next 2-3 years, with completion of the new Mitsubishi Petrochemical facility. Glycol capacity is currently at the 575,000 metric tons per year level, and it will increase by 100,000 metric tons per year, as is shown in Table IV-G-3.

TABLE IV-G-3

JAPANESE ETHYLENE OXIDE/GLYCOL PRODUCERS
(Thousand Metric Tons per Year)

Company	Capacity		Expansions
	Ethylene Oxide	Ethylene Glycol	
Mitsubishi Petrochemical	105	95	120/100 (early 1980s)
Mitsui Petrochemical	207	190	
Nippon Catalytic Chemical	195	180	
Nisso Petrochemical	128	110	
	635	575	

Supply/Demand Situation

The supply/demand balance for ethylene oxide in Japan is shown in Table IV-G-4. Basically, existing and announced capacity is sufficient to meet demand until 1985.

TABLE IV-G-4

POTENTIAL SUPPLY/DEMAND BALANCE FOR ETHYLENE OXIDE IN JAPAN
(Thousand Metric Tons)

	1977	1978	1980	1985	1990
Potential supply*	635	635	635	755	755
Forecast demand	538	631	615	775	925
Surplus/(deficit)	97	4	20	(20)	(170)
Actual production	538	631			
Operating rate, %	85	99			

* 100 percent of nameplate capacity.

Pricing

In August 1979, the Japanese prices for industrial and antifreeze ethylene glycol were 184 and 178 yen per kilo, respectively (38 and 36.8 cents per pound). Glycol prices are primarily related to ethylene costs.

b. Korea

Polyester fiber production represents almost all ethylene glycol use in Korea. A small amount is used as antifreeze. The Korean demand for ethylene glycol is forecast to grow from 80,000 metric tons in 1978 to 220,000 metric tons in 1990, as shown in Table IV-G-5. About 70 percent of Korean polyester fiber production is exported, primarily in the form of finished goods.

TABLE IV-G-5

KOREAN ETHYLENE GLYCOL DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
Polyester fiber production	158	190	250	380	520	8.8
Ethylene glycol requirement	65	75	100	150	210	8.8
Other glycol uses	4	5	6	8	10	-
Total demand	69	80	106	158	220	8.8

At present, there are no ethylene glycol producers in Korea. However, an 80,000 metric ton per year facility in which Mitsui is a part owner is under construction at Yeosu. Completion is anticipated in 1979. Since demand is increasing at a faster pace than capacity, Korea is expected to be an importer of the product in increasing volumes throughout the early 1980s.

c. Taiwan

Almost all ethylene glycol in Taiwan is used for the production of polyester fibers. The polyester fiber industry relies almost completely upon exports since domestic consumption represents only about 10 percent of production. Of the material exported, about half is shipped as filament and yarn, while the remainder is in the form of finished goods and textiles. As shown in Table IV-G-6, ethylene glycol demand in Taiwan is expected to increase from 85,000 metric tons in 1977 and 120,000 metric tons in 1978 to 160,000, 240,000 and 300,000 metric tons in 1980, 1985 and 1990, respectively.

TABLE IV-G-6

TAIWAN ETHYLENE GLYCOL DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
Polyester fiber production	210	300	400	600	750	8.0
Ethylene glycol demand	85	120	160	240	300	8.0

The current ethylene glycol capacity in Taiwan is 175,000 metric tons per year. Capacity will be increased by 50,000 metric tons per year when the planned petrochemical complex at Lin Yuan comes on stream in 1983, as shown in Table IV-G-7.

TABLE IV-G-7

TAIWAN ETHYLENE GLYCOL PRODUCERS, 1978
(Thousand Metric Tons per Year)

Company	Location	Capacity	Expansions
China Man-Made Fiber	Kaohsiung	50	
Oriental Union Chemical	Kaohsiung	125	50 (1983)
		175	

The China Man-Made unit was completed in early 1976. The firm is 100 percent owned by local interests. The Oriental Union Chemical plant is owned by Oriental Chemical (20 percent), China Development (25 percent), Central Investment (30 percent) and Union Carbide (25 percent). Union Carbide is currently handling export sales from this plant and has been active in Southeast Asian markets.

d. Hong Kong

The current demand for ethylene glycol in Hong Kong is about 200 metric tons per year and is expected to remain small since it is very unlikely that polyester fiber production will commence in spite of substantial demand in the Colony. This is due to the absence of import duties and business relationships between local textile producers and Japanese fiber producers.

There are no producers of ethylene glycol in Hong Kong nor are any expected throughout the study period.

e. ASEAN Countries

Polyester fiber production is the only use for ethylene glycol in the ASEAN countries. Polyester fiber production within the ASEAN group and

estimated ethylene glycol consumption by country are presented in Table IV-G-8. Ethylene glycol consumption is forecast to increase from 57,000 metric tons in 1977 and 69,000 metric tons in 1978 to 77,000, 98,000 and 126,000 metric tons in 1980, 1985 and 1990, respectively.

TABLE IV-G-8

ASEAN COUNTRY ETHYLENE GLYCOL DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
ASEAN country polyester fiber production	142	171	195	247	317	5.3
Ethylene glycol						
Philippines	9	10	11	16	25	7.9
Singapore	-	-	-	-	-	-
Malaysia	12	13	14	14	14	0.6
Thailand	20	28	30	36	44	3.8
Indonesia	16	18	23	32	43	7.5
Total ethylene glycol demand	57	69	78	98	125	5.3

At present, there are no ethylene glycol facilities within the ASEAN countries. A 120,000 metric ton per year facility is planned as part of the Singapore petrochemical project. This plant would be at least partially owned by the four Japanese ethylene glycol producers. Completion is anticipated in the 1982-1983 period. Firms have also been investigating the possibility of erecting a facility in Indonesia, but completion before 1985 appears unlikely.

A large part of the polyester fiber industry in the ASEAN countries is controlled by affiliates of the Japanese fiber companies. These firms have traditionally purchased most of their ethylene glycol from Japanese sources.

f. People's Republic of China

Ethylene glycol consumption in the PRC will grow rapidly due to the planned emphasis on polyester fibers. However, it is anticipated that essentially all of the ethylene glycol required will ultimately be produced within the country.

3. Conclusions

Opportunities for an Alaskan Plant

Supply and demand for ethylene glycol on the West Coast and in the Pacific Basin are summarized in Table IV-G-9.

TABLE IV-G-9

ETHYLENE GLYCOL

	Demand				Capacity, per year	
	1978	1985	1990	AAGR, %*	1978	Future
		(Million Pounds)				
West Coast	200	232	248	1.8	0	0
		(Thousand Metric Tons)				
Japan	410	575	675	4.2	575	675
Korea	80	158	220	8.8	0	80
Taiwan	120	240	300	8.0	175	225
Hong Kong	neg.	neg.	neg.	-	0	0
ASEAN Countries	69	98	126	5.3	0	120*

* Future project not certain.

The ethylene glycol market available to a new producer is small and has little prospect for growth. Korea and the ASEAN countries are the only countries in the Pacific Basin region which will require imports of ethylene glycol during the mid-1980s. However, since much of the fiber industry in these countries is controlled by Japanese firms, it is anticipated that almost all of the ethylene glycol required will be supplied by Japan, either directly or through the Singapore project and by Taiwan, which will have considerable excess capacity until the mid-1980s.

H. Ethylene

Ethylene boils at -119°F and must be shipped in cryogenic tankers. As a result, shipment of ethylene is not widespread and is primarily limited to coastal movements in Japan and special situations in Europe. It is generally preferable to ship ethylene in the form of derivatives rather than as the product itself.

Shipment of liquid ethylene to West Coast markets for derivative manufacture would have to compete with derivatives manufactured in large facilities on the Gulf Coast. This is not considered to be a viable alternative.

The only really large potential market for liquid ethylene in the Pacific Basin countries would be in Japan. On the basis of discussions with major Japanese companies, it is felt that importation (vs incremental production in existing plants) would not be viable due to the high costs for transportation and the necessity of building a large receiving and storage terminal. It is felt that Japanese firms would prefer to import ethylene in the form of derivatives, especially derivatives such as ethylene dichloride or vinyl chloride monomer, which are energy-intensive.

At present, projects based upon imported ethylene are being planned in the Philippines and Thailand. The Philippine project would require up to 90,000 metric tons per year for LDPE manufacture, while the Thai project would require 90,000 and 50,000 metric tons per year for LDPE and HDPE manufacture, respectively. Completion of both projects is planned for the 1983-1985 period, but additional delays could occur. In both cases, eventual ethylene production at the plant site is anticipated. As a result, supplying some incremental ethylne to these projects from an Alaskan plant is feasible, but shipment of liquid ethylene on a large scale for a long period of time does not appear to be viable.

I. Polypropylene

1. West Coast Market

a. Demand

The demand for polypropylene resin in the U.S. West Coast region in 1977 and 1978 is estimated at 110 and 125 million pounds, respectively. In addition, some polypropylene film was shipped into the region by converters during the year. Compared to the total U.S. market, the western consumption of resin in small, being only 4.6 percent of the U.S. total. The reason for this is that the West Coast states do not have the three largest consuming industries for polypropylene, namely fibers, automotive component production and major appliances.

By 1990, demand is expected to total 355 million pounds, an average annual growth rate of 9.1 percent over the 1978-1990 period. The growth pattern, by broad end use category, is shown in Table IV-I-1. Western Canadian demand is currently 5-10 million pounds and is anticipated to reach 20 million pounds by 1990.

TABLE IV-I-1

WEST COAST POLYPROPYLENE DEMAND
(Million Pounds)

Western U.S.	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
Injection molding	69	73	90	130	190	8.3
Film and sheet	6	7	10	15	20	9.1
Fiber and filaments	-	-	-	-	-	-
Other extrusions	20	25	30	45	70	9.0
All other uses	15	20	30	55	75	11.6
Total Western U.S.	110	125	160	245	355	9.1
Western Canada	5	5	10	15	20	12.0
Total	115	130	170	260	375	9.1

The largest end use in the U.S. West Coast region is that of injection molding, which accounts for about 60 percent of polypropylene consumption. Typical uses for injection-molded products are food

containers, nursery tubs, toys, instrumentation, housewares, medical uses and battery cases. Film and sheet, mainly for packaging, account for only 5-6 percent of the resin use. The remaining resin is used for extruded pipe, for cordage, for sweeper brushes and for wire coating.

Injection molding consumed an estimated 73 million pounds of polypropylene resin in 1978. This end use is expected to grow to 190 million pounds by 1990, an 8.3 percent average annual growth rate. The end-use markets for injection-molded products are varied. They include food containers by Triplastics, pens by Paper Mate, razors by Gillette, spray pumps by Calmar, toys by Mattel, medical products by Cutter Labs and battery cases, which are made by Amerace, Gould, Delco, Globe Union and Richardson.

Film and sheet needs for resin are relatively small, with very few companies actually extruding film. A number of companies convert polypropylene film, which is shipped to the West Coast from the Gulf Coast.

Among the extruders of film on the West Coast are Richland Corporation, Crown Zellerbach and Dixico (La Mirada, CA). Gage Industries of Oregon is the only extruder of polypropylene sheet on the West Coast.

Extrusions, other than for film, fibers and filaments, accounted for 25 million pounds of resin in 1978. There was consumption of polypropylene resin for straws by NSF, Diamond Straw and Maryland Corporation; for rope and cordage by Tubs Cordage and Straplock; and for extruded pipe by U.S. Plastic Pipe and R. H. Sloane.

All other uses, consuming 20 million pounds of resin in 1978, included substantial amounts for medical use, specifically saline solutions. There is also some blow molding carried out by Continental Can. In addition, glass-reinforced polypropylene is being used in appliances.

The Western Canadian polypropylene market is currently in the 5-10 million pound per year range. It is anticipated to reach 20 million

pounds by 1990. Among the consumers are Canada Western Cordage, Vancouver (monofilament) and Cameo Plastic Products, Langley, B.C. (drinking straws).

b. Supply

There are no producers of polypropylene resin in the U.S. West Coast region. The demand for resin is met mostly by six U.S. producers: Hercules, Exxon, Eastman, Dart, Amoco and Novamont. Hercules is by far the largest supplier. Hercules is the sole Canadian producer, and Shell is also starting up a facility; both of these plants are in Eastern Canada. These firms and other U.S. producers serve the Canadian market.

c. Captive Consumption

Captive consumption of polypropylene on the West Coast is small, and it is anticipated that the percentage will remain low through the study period. There is no captive consumption in Western Canada.

d. Pricing

The price of polypropylene in the Western U.S. was 32 cents per pound for the homopolymer, delivered in bulk. Copolymer prices are 3 cents per pound higher. Canadian prices are $0.38 and 0.42 (Canadian) per pound, respectively. Canadian imports of polypropylene are subject to a 10 percent ad valorem duty.

2. Pacific Basin Market

a. Japan

Demand

Japanese domestic demand for polypropylene is forecast to increase from 507,000 metric tons in 1977 and 577,000 metric tons in 1978 to 1,045,000 metric tons in 1990, an average annual growth of 5.1 percent. In addition, Japan has been a significant exporter of polypropylene, with

exports totaling 136,000 metric tons in 1978. Exports are anticipated to decline somewhat in future due primarily to the impact of new facilities in the region. Japanese polypropylene demand by end use is presented in Table IV-I-2.

TABLE IV-I-2

JAPANESE POLYPROPYLENE DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
Domestic demand						
Film	152	171	205	260	320	5.4
Injection molding	206	239	285	360	435	5.1
Blow molding	20	20	23	30	40	5.9
Film yarn	47	61	67	85	105	4.6
Fiber	28	29	30	30	30	-
Extrusion and misc.	54	57	65	90	115	6.0
Total domestic demand	507	577	675	855	1,045	5.1
Exports	124	136	100	95	85	-
Total demand	631	713	775	950	1,130	3.9

Both cast and oriented polypropylene are produced in Japan. Since usage of these products is considerably greater than in the U.S. and polypropylene has already penetrated most potential markets, demand growth is anticipated to be in line with GNP growth. Injection molding applications are the largest use for the product. Demand is expected to increase about 5 percent per year. Slit film yarn for bags and carpet backing is a relatively mature market, and Japan is facing increased competition from South Korea and Taiwan in export markets. Polypropylene fiber is relatively minor in Japan since very little is used as a carpet face fiber and in upholstery. Significant applications for fiber include rope and other industrial uses and as a filler in comforters. In this latter application, polypropylene is facing increased competition from polyester.

Supply

The present capacity of the Japanese polypropylene industry is 1.1 million metric tons, as shown in Table IV-I-3. New facilities by Chubu,

Mitsui Petrochemical, and Tonen and are anticipated to increase capacity by 200,000 metric tons per year by the early 1980s. In addition, Sumitomo will probably build a facility in the 100,000 metric ton per year range if their proposed plant in Singapore is not built.

TABLE IV-I-3

JAPANESE POLYPROPYLENE PRODUCERS, 1978

Company	Location	Capacity	Expansions
Chisso	Chiba	155	
Chubu	Yokkaichi		40
Idemitsu	Chiba	60	
Mitsubishi Chemical	Mizushima	30	
Mitsubishi Petrochemical	Yokkaichi	105	
	Kashima	85	
Mitsui Petrochemical	Chiba	120	100
Mitsui-Toatsu	Ohtake	90	
	Senpoku	65	
Showa Petrochemical	Ohita	75	
Sumitomo	Chiba	96	
	Niihama	30	
Tonen	Kawasaki	60	60
Tokuyama Soda	Tokuyama	70	
Ube	Sakai	90	
Total		1,131	200

Supply/Demand Situation

The potential supply/demand situation for polypropylene in Japan is presented in Table IV-I-4. Existing and announced capacity for the product is sufficient to meet domestic demand plus significant export demand through the study period. Polypropylene is a product in which the Japanese specialize, and there is little potential for exports from an Alaskan plant to Japan under ordinary circumstances.

TABLE IV-I-4

POTENTIAL SUPPLY/DEMAND BALANCE FOR POLYPROPYLENE IN JAPAN
(Thousand Metric Tons)

	1978	1980	1985	1990
Potential supply*	1,131	1,131	1,331	1,331
Forecast demand	713	775	950	1,130
Surplus/(deficit)	418	356	381	201

* 100 percent of nameplate capacity.

Pricing

In late June 1979, the price for polypropylene was 210 yen per kilo (43.4 cents per pound), delivered. Polypropylene prices in Japan depend upon propylene costs, and they tend to be similar to prices for polystyrene resins, with which they compete. Polypropylene imports into Japan are subject to an 8 percent ad valorem duty.

b. Korea

Demand

In 1978, the Korean polypropylene demand was 131,000 metric tons. Demand is anticipated to reach 170,000, 245,000 and 330,000 metric tons by 1975, 1980 and 1985, respectively. Woven bags constitute the largest market. Film, fiber and injection-molded articles are also made.

Supply

The sole Korean producer of polypropylene is Korea Petrochemical Industry Company (50 percent Korean interests/50 percent Chisso, Marubeni) at Ulsan, which has facilities capable of producing 110,000 metric tons per year of high density polyethylene and polypropylene. Capacity was increased to 140,000 metric tons per year during 1978 by adding a new line.

About one-third of the propylene feedstock for the unit is obtained from Korea Oil, with the remainder being obtained from imports from Europe, Japan and the U.S. The firm anticipates being a propylene importer until the Yeosu project comes on stream, at which time it will receive propylene from this source.

Honam Petrochemical (50 percent Honam Ethylene (Korean Government)/50 percent Mitsui Group) is also constructing an 80,000 metric ton per year unit at Yeochon, which is anticipated to be on stream during 1980.

Supply/Demand Situation

The potential supply/demand situation for polypropylene in Korea is shown in Table IV-I-5.

TABLE IV-I-5

POTENTIAL SUPPLY/DEMAND BALANCE FOR POLYPROPYLENE IN KOREA
(Thousand Metric Tons)

	1977	1978	1980	1985	1990
Potential supply*	55	70	150	150	150
Forecast demand	123	131	170	245	330
Surplus/(deficit)	(68)	(61)	(20)	(95)	(180)
Actual production	110	74			

* Ulsan plant taken at 50 percent capacity for polypropylene.

Basically, even with expansion of the Korean Petrochemical Industry plant and the new Honam Petrochemical facility, Korea will remain a net importer of polypropylene. The country cannot, however, be considered a long-term consumer of material from an Alaskan plant.

c. Taiwan

The demand for polypropylene in Taiwan is anticipated to increase from 55,000 metric tons in 1977 and 74,000 metric tons in 1978 to 225,000

metric tons in 1990, as shown in Table IV-I-6. Consumption is primarily for the production of molded items and film for packaging applications and for slit film. Polypropylene fiber consumption is relatively small.

TABLE IV-I-6

TAIWAN POLYPROPYLENE DEMAND
(Metric Tons)

1977	55,000
1978	74,000
1980	95,000
1985	155,000
1990	225,000
AAGR, % (1978-1990)	9.7

Taiwan Polypropylene, in which Hercules has an interest, is the sole producer of polypropylene at present, with a 50,000 metric ton per year facility. This plant started up in late 1976, and there are plans to double the size of the plant in the early 1980s. Formosa Plastics is planning an 80,000 metric ton per year plant as part of a new petrochemical complex at Lin Yuan. Start-up is expected in 1982. As a result, there should be some export opportunities to Taiwan in the early 1980s, but Taiwan cannot be considered as a long-term export market from an Alaskan facility. The supply/demand balance for the product is shown in Table IV-I-7.

TABLE IV-I-7

POTENTIAL SUPPLY/DEMAND BALANCE FOR POLYPROPYLENE IN TAIWAN
(Thousand Metric Tons)

	1977	1978	1980	1985	1990
Potential supply*	45	45	45	165	165
Forecast demand	55	74	95	155	225
Surplus/(deficit)	(10)	(29)	(50)	10	(60)

* 90 percent of nameplate capacity.

d. Hong Kong

The demand for polypropylene in Hong Kong is anticipated to increase from 18,000 metric tons in 1978 to 41,000 metric tons in 1990, as shown in Table IV-I-8. Demand in Hong Kong is essentially for production of molded articles and film. Although Hong Kong has a very large polystyrene consumption, it is anticipated that the inroads of polypropylene into these markets will be relatively modest. As a result, demand for polypropylene in the Colony will remain small relative to that for polyethylene and polystyrene.

TABLE IV-I-8

HONG KONG POLYPROPYLENE DEMAND
(Metric Tons)

1977	15,000
1978	18,000
1980	25,000
1985	33,000
1990	41,000
AAGR, % (1978-1990)	7.1

At present there are no polypropylene producers in Hong Kong, and none are foreseen. Hong Kong represents a long-term export market from an Alaskan facility, but unfortunately the market is relatively small.

e. ASEAN Countries

Demand

The demand for polypropylene in the ASEAN countries is anticipated to increase from 94,000 and 105,000 metric tons in 1977 and 1978 to 303,000 metric tons in 1990. The forecast demand, by country, is presented in Table IV-I-9. Most of the demand is in film and injection molding applications. Indonesia is the largest market, with consumption being relatively high due to the use of polypropylene in some traditional polyethylene applications. This is due to the efforts of Pertamina, which has a polypropylene facility.

TABLE IV-I-9

ASEAN COUNTRY POLYPROPYLENE DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (Base 1978)
Philippines	26	28	35	64	95	10.7
Singapore	6	7	9	14	18	8.2
Malaysia	12	15	18	26	35	7.3
Thailand	17	19	22	35	55	9.3
Indonesia	33	36	45	70	100	8.9
Total	94	105	119	209	303	9.2

Supply

The only polypropylene plant in the ASEAN countries is the 20,000 metric ton per year plant of Pertamina in Indonesia. Propylene from an adjacent refinery is used as the feedstock and, as a result of refining operating conditions, polypropylene production was only about 6,000 metric tons in 1978. No change in this situation is foreseen at least through the mid-1980s.

Two additional projects for the region have been announced: Sumitomo has plans for a 100,000 metric ton per year facility as part of the Singapore petrochemical complex, scheduled to come on stream in 1983, and Hercules has plans for a 60,000 metric ton per year plant as part of the Philippines petrochemical project. The latter project is not firm at present.

Supply/Demand Situation

The supply/demand balance within the ASEAN group will depend upon the completion of the proposed projects. By 1985 the Sumitomo project will be on stream, and by 1990 the Philippines project should be on stream. As a result, imports are anticipated to remain at over 100,000 metric tons from 1985 to 1990.

f. People's Republic of China

Capacity for production of polypropylene in the PRC is about 40,000 metric tons per year. Imports of the products are anticipated to be relatively small.

3. Conclusions

Opportunities for an Alaskan Plant

The supply and demand for polypropylene on the West Coast and in the Pacific Basin are summarized in Table IV-I-10.

TABLE IV-I-10

POLYPROPYLENE

	Demand				Capacity, per year	
	1978	1985	1990	AAGR, %*	1978	Future
		(Million Pounds)				
West Coast	130	260	375	9.1	0	0
		(Thousand Metric Tons)				
Japan	577	855	1,045	5.1	1,131	1,331
Korea	131	245	330	8.0	70	150
Taiwan	74	155	225	9.7	50	180
Hong Kong	13	33	41	7.1	0	0
ASEAN Countries	105	209	303	9.2	20	100-200*

* Future projects not certain.

During the 1980s, it is anticipated that new grass-roots polypropylene facilities will have to be at least 220 million pounds per year in size in order to be competitive. Because the market is dominated by Hercules, it is anticipated that a polypropylene producer with a West Coast plant could, at most, expect to obtain 25 percent of the market. However, this would amount to 65 million pounds in 1985, or less than 30 percent of plant capacity.

In 1985, the Pacific Basin countries are anticipated to have imports totaling 400-500 million pounds, of which at least half would be supplied from countries within the area. Because a large number of firms compete for this business, the maximum exports to the Pacific Basin region would be about 40 million pounds.

Unless the firm were already a major polypropylene supplier to the region, polypropylene production would not be too attractive, except to utilize propylene feedstock that had no other use.

AGO 559712

J. Phenol

1. West Coast Market

a. Demand

The demand for phenol on the West Coast is forecast to increase from about 305 million pounds in 1978 to 520 million pounds in 1990, as shown in Table IV-J-1. Phenolic resins, alkylphenols and some specialty products are the only phenol derivatives produced within the region.

TABLE IV-J-1

WEST COAST PHENOL DEMAND
(Million Pounds)

Western U.S.	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
Phenolic resins	225	235	265	325	385	4.2
Bisphenol-A	-	-	-	-	-	-
Caprolactam	-	-	-	-	-	-
Alkylphenols	10	10	11	13	15	3.4
Phenolic plasticizers	-	-	-	-	-	-
Salicylic acid	-	-	-	-	-	-
2,6-Xylenol	-	-	-	-	-	-
Miscellaneous	30	35	39	52	70	6.0
Total Western U.S.	265	280	315	390	470	4.4
Western Canada	25	25	30	40	50	5.9
Total	290	305	335	430	520	4.5

Phenolic resins represent over 80 percent of U.S. West Coast phenol consumption. In 1978, an estimated 320 million pounds of phenolic resins were consumed, or about 18 percent of overall U.S. consumption. The major use is in plywood manufacture, although hardboard, laminates and insulation usage is also significant. West Coast phenolic resin producers include Reichhold, Borden, Georgia-Pacific, Monsanto, Skelly, Simpson Timber, Univar and Weyerhauser.

Alkylphenol production on the U.S. West Coast was estimated at 25 million pounds in 1978. The largest use areas for alkylphenols are surfactants, lube oil additives, resin copolymers and rubber and plastic additives.

Kalama Chemical produces nonylphenol in Kalama, Washington, at its 20 million pound per year capacity plant. Productol has a 5 million pound per year capacity plant in Santa Fe Springs, California, and also has a small capacity for producing octylphenol.

Miscellaneous uses of phenol accounted for an estimated 35 million pounds in 1978. This category includes phenolphthalein, 2,4-D, pentachlorophenol, petroleum refining, para-tert-butylphenol and agricultural chemicals.

Phenolic consumption in Western Canada was about 25 million pounds in 1978, and consumption is expected to double by 1990. Consumption is almost entirely for phenolic resin production from plywood, particle board and glass fiber insulation use. The phenolic resin producers in Western Canada are Reichhold at Port Moody and Kamloops and Borden at Vancouver. Each of these firms has 40-50 million pounds per year of resin capacity.

Cumene

Actual cumene consumption on the West Coast is about 70 million pounds per year. Potential cumene demand, if the region were self-sufficient in phenol, is forecast to increase from 315 million pounds in 1978 to 600 million pounds in 1990, as shown in Table IV-J-2. Cumene is not the only feedstock for phenol in the region, since Kalama Chemical and Dow at Ladner, B.C. utilize toluene.

TABLE IV-J-2

POTENTIAL U.S. WEST COAST CUMENE DEMAND
(Million Pounds)

	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
Phenol demand	290	305	335	430	520	4.5
Less: phenol by other routes	80	80	90	90	90	
Phenol from cumene	210	225	245	340	430	
Cumene requirement	295	315	345	475	600	

AGO 559714

b. Supply

Chevron is the only producer of cumene in the Western region, with a 100 million pound per year plant at El Segundo, CA. Chevron uses its cumene captively for the production of phenol and acetone in a 55 million pounds per year phenol plant. Kalama Chemical at Kalama, WA, and Dow at Ladner, B.C., also produce phenol, but by the toluene oxidation route. The West Coast phenol producers are summarized in Table IV-J-3. Productol recovers small quantities of natural phenol at its Santa Fe Springs, CA, facility.

TABLE IV-J-3

U.S. WEST COAST PHENOL PRODUCERS, 1978
(Million Pounds per Year)

Company	Location	Capacity	Process
Chevron	Richmond, CA	55	Cumene
Dow	Ladner, BC	30	Toluene Oxidation
Kalama Chemical	Kalama, WA	80	Toluene Oxidation
Productol	Sante Fe Springs, CA	neg.	Natural
Total		165	

All of the U.S. phenol producers, except Clark, are reported to market on the West Coast. In addition to the local producers, Shell, Dow and Monsanto are major suppliers. Dow supplies the entire Western Canadian market.

c. Captive Market

It is estimated that the captive market for phenol in the Western region was about 130-140 million pounds in 1978. Among the largest users of phenol for phenolic resins in the region are Monsanto, Reichhold, Skelly and Georgia-Pacific. Chevron uses phenol internally for agricultural products, and Kalama and Productol produce alkylphenols. No significant change in the percentage of captive consumption is anticipated over the study period.

d. Pricing

The U.S. price for phenol was 36 cents per pound as of October 1, 1979. Canadian prices were $0.45 (Canadian) per pound for the Eastern Canadian plants. Phenol prices are primarily related to the price and availability of benzene feedstock and the supply/demand situation for the product. Phenol imports into Canada are subject to a 15 percent ad valorem duty, but some Canadian resin producers are able to take advantage of duty drawback situations.

2. Pacific Basin Market

a. Japan

Demand

Japan's domestic demand for phenol is forecast to increase from 202,000 metric tons in 1978 to 405,000 metric tons in 1990, a growth rate of 3.9 percent per year over the period. Imports are due to the cumene toll processing agreement between Mitsubishi Petrochemical and Dow. Exports should decline throughout the study period, reaching zero by 1990.

The Japanese demand for phenol is presented in Table IV-J-4.

TABLE IV-J-4

JAPANESE PHENOL DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
Phenolic resins	106	110	125	175	240	6.7
Bisphenol-A	55	53	55	70	90	4.5
Alkylphenols	15	15	15	20	30	5.9
Phenolic plasticizers	2	2	2	3	4	6.0
Aniline	20	20	21	24	37	5.3
Other	2	2	2	3	4	6.0
Total domestic	200	202	220	295	405	6.0
Exports	33	53	25	5	-	-
Total demand	233	255	245	300	405	3.9

Phenolic resins demand is forecast to grow at around 6.7 percent per year. Bisphenol-A is used in Japan primarily for epoxy resins (50 percent) and polycarbonates (45 percent). Growth of bisphenol-A demand for epoxies and polycarbonates has been slower than in other parts of the world, and a relatively slow growth of only 4.5 percent is projected for the study period. Alkylphenols are used for alkylphenol ethoxylate manufacture and for production of lube oil additives, agricultural chemicals and antioxidants. Demand growth should average nearly 6 percent over the study period. Aniline is produced from phenol by Mitsui Petrochemical, and the aniline needs of the Mitsui group tend to be met from this source. Other applications include surfactants, agricultural chemicals, pharmaceuticals, plasticizers and stabilizers.

Supply

Current phenol capacity is 316,000 metric tons per year, as indicated in Table IV-J-5. No expansions are in progress. However, a new 100,000 metric ton per year plant, which should be built in the 1980s, is being planned by Mitsubishi Petrochemical. As a result, Japan is anticipated to be self-sufficient in phenol.

TABLE IV-J-5

JAPANESE PHENOL PRODUCERS, 1979
(Thousand Metric Tons per Year)

Company	Location	Capacity	Process
Mitsui Toatsu	Senpoku	100	Cumene
	Nagoya	36	Sulfonation
Mitsui Petrochemical	Chiba	150	Cumene
	Iwakuni	30	Cumene
		316	

Pricing

The Japanese price for phenol was 220 yen per kilo (45.4 cents per pound) as of early August. Phenol imports are subject to an 8 percent duty.

b. Korea

Korean demand for phenol was about 9,000 metric tons in 1977 and 10,000 metric tons in 1978. Demand should reach 14,000, 24,000 and 35,000 metric tons by 1980, 1985 and 1990, respectively. Use is primarily for the production of resins.

Keumho Chemical is constructing a 25,000 metric ton per year phenol plant at Yeosu. This facility and an associated 35,000 metric ton per year cumene unit should be on stream in the 1979-1980 period. As a result, Korea should be self-sufficient in phenol through the mid-1980s.

c. Taiwan

The demand for phenol in Taiwan was about 5,000 metric tons in 1977 and 8,000 metric tons in 1978. Demand is forecast to reach 12,000, 18,000 and 24,000 metric tons by 1980, 1985 and 1990, respectively. Essentially all demand is for the manufacture of phenolic resins.

At present, there is no phenol production in Taiwan. The government has been attempting to promote production of the material, but the low demand makes production unlikely until at least the mid-1980s.

d. Hong Kong

The demand for phenol in Hong Kong is about 300-400 metric tons per year. In addition, the Colony imports about 4,000 metric tons per year of phenolic resins. The demand for phenol is anticipated to remain small, and no local production is foreseen.

e. ASEAN Countries

Phenol demand in the ASEAN countries is forecast to increase from 7,800 and 12,000 metric tons in 1977 and 1978 to 14,100, 17,900 and 22,800 in 1980, 1985 and 1990, respectively, as shown in Table IV-J-6. Essentially all of the material is used in the production of plywood adhesives.

There are no phenol producers in the ASEAN countries, and no production is anticipated during the study period.

TABLE IV-J-6

ASEAN COUNTRY PHENOL DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (Base 1978)
Philippines	1.9	2.2	2.4	2.9	3.5	3.9
Singapore	2.7	5.0	5.5	6.0	6.5	2.2
Malaysia	2.6	4.0	5.0	6.5	8.3	6.3
Thailand	0.6	0.7	1.0	2.0	3.0	12.9
Indonesia	nil	0.1	0.2	0.5	1.5	25
Total	7.8	12.0	14.1	17.9	22.8	5.5

f. People's Republic of China

Phenol imports to the PRC are very small.

3. Conclusions

Opportunities for an Alaskan Plant

The supply and demand for phenol on the West Coast and in the Pacific Basin are summarized in Table IV-J-7.

TABLE IV-J-7

PHENOL

	Demand				Capacity, per year	
	1978	1985	1990	AAGR, %	1978	Future
	(Million Pounds)					
West Coast	305	430	520	4.5	0	165
	(Thousand Metric Tons)					
Japan	202	295	405	6.0	316	416
Korea	10	24	35	11.0	0	30
Taiwan	8	18	24	9.6	0	0
Hong Kong	neg.	neg.	neg.	-	0	0
ASEAN Countries	12	18	23	5.5	0	0

During the 1980s, the minimum size for a phenol plant will be 400-500 million pounds per year. The relatively small merchant market on the West Coast, coupled with small markets in the Pacific Basin countries, makes production in Alaska relatively unattractive under normal circumstances.

AGO 559720

K. Acrylonitrile

1. West Coast Market

a. Demand

The U.S. West Coast demand for acrylonitrile was about 7-8 million pounds in 1978. It is expected to grow to about 10 million pounds in 1985 and 13 million pounds by 1990. The only major market for the product on the West Coast is for the production of ABS resins by Dow, which is a merchant consumer. There is no acrylonitrile consumption in Western Canada.

b. Supply

There are no producers of acrylonitrile in the West Coast region. Abundant capacity exists in the U.S. to supply this region.

c. Captive Market

There is no captive consumption of acrylonitrile on the West Coast.

d. Pricing

The price for acrylonitrile as of October 1, 1979, was 27.5 cents per pound.

2. Pacific Basin Market

a. Japan

Demand

Japanese domestic acrylonitrile demand is forecast to increase from 515,000 metric tons in 1978 to 550,000, 700,000 and 860,000 metric tons in 1980, 1985 and 1990, respectively. This represents an average annual

growth of 4.4 percent. Exports were 95,000 metric tons in 1978, and these are expected to decrease due to the addition of plant capacity in Korea, the major export market. On an overall basis, demand is expected to increase from 610,000 metric tons in 1978 to 930,000 metric tons in 1990, as shown in Table IV-K-1.

TABLE IV-K-1

JAPANESE ACRYLONITRILE DEMAND
(Thousand Metric Tons)

	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
Acrylic fiber	320	320	335	430	525	4.2
ABS resin and nitrile rubber	85	90	100	130	160	4.9
Others	100	105	115	140	175	4.3
Total domestic demand	505	515	550	700	860	4.4
Exports	90	95	60	60	70	-
Total demand	595	610	610	760	930	3.6

About 60-65 percent of Japanese acrylonitrile is in the production of acrylic fibers. Acrylic fiber demand is expected to grow at nearly 5 percent per year, due to the growth of the Japanese carpet market. In 1978, imports of acrylic staple from the U.S. rose sharply, due primarily to the lower cost of the U.S. products. In Japan, higher naphtha prices have resulted in imports of U.S. acrylic fiber selling for about 20 percent less than the domestic product. It is believed that Japan will limit these imports by 1980 through the imposition of import tariffs or other means. Acrylonitrile demand for fibers is thus expected to exhibit slow growth until about 1980 and then average about 4 to 5 percent per year throughout the study period. ABS resins will have a growth of about 5 percent per year. Other applications include acrylamide and adiponitrile for hexamethylenediamine production.

Supply

At the end of 1978, Japanese acrylonitrile capacity totaled 744,000 metric tons, divided among seven producers. The Japanese acrylonitrile producers are shown in Table IV-K-2.

TABLE IV-K-2

JAPANESE ACRYLONITRILE PRODUCERS

Asahi Chemical Industry
Mitsubishi Chemical
Mitsui Petrochemical
Mitsui-Toatsu
Nitto Chemical
Showa Denko
Sumitomo Chemical

Supply/Demand Situation

The supply/demand for acrylonitrile in Japan is relatively tight, as shown in Table IV-K-3. In 1978, the operting rate was 82 percent, and additional capacity will be required by 1985 in order to meet demand growth.

TABLE IV-K-3

POTENTIAL SUPPLY/DEMAND BALANCE FOR ACRYLONITRILE IN JAPAN
(Thousand Metric Tons)

	1977	1978	1980	1985	1990
Potential supply*	744	744	744	744**	744**
Forecast demand	595	610	610	760	930
Surplus/(deficit)	149	134	134	(16)	(186)
Operating rate, %	80	82	82	-	-

* 100 percent of nameplate capacity.
** Additional expansions likely.

Pricing

The Japanese acrylonitrile price was 210 yen per kilo (43.4 cents per pound) in early August 1979. Imports of acrylonitrile into Japan are subject to an 8 percent ad valorem duty.

AGO 559723

b. Korea

The Korean demand for acrylonitrile was 116,000 metric tons in 1977 and 124,000 metric tons in 1978. Demand is forecast to reach 150,000, 190,000 and 240,000 metric tons in 1980, 1985 and 1990, respectively. Acrylic fiber is the major use, but there is also demand for ABS resins and other applications.

The sole producer of acrylonitrile in Korea is Tongsuh Petrochemical, which expanded capacity from 27,000 to 77,000 metric tons per year in 1978. An additional 100,000 metric tons of capacity are planned at the third petrochemical complex at Yochon, which is expected to be on stream by the mid-1980s.

c. Taiwan

Domestic demand for acrylonitrile in Taiwan increased from 53,000 metric tons in 1977 to 84,000 metric tons in 1978. It is expected to increase to 105,000, 154,000 and 198,000 metric tons in 1980, 1985 and 1990, respectively.

Acrylic fiber is the major application for acrylonitrile, representing over 90 percent of the demand. Acrylic fibers are used in the country's export-oriented textile business.

China Petrochemical Development Corporation is the only producer of acrylonitrile in Taiwan, with a nameplate capacity of 132,000 metric tons per year. The country has sufficient capacity to meet demand until the early 1980s.

d. Other Countries

Other countries in the Pacific Basin area do not consume acrylonitrile.

3. Conclusions

Opportunities for an Alaskan Plant

The supply and demand for acrylonitrile on the West Coast and in the Pacific Basin are summarized in Table IV-K-4.

TABLE IV-K-4

ACRYLONITRILE

	Demand				Capacity, per year	
	1978	1985	1990	AAGR, %	1978	Future
	(Million Pounds)					
West Coast	8	10	13	4.2	0	0
	(Thousand Metric Tons)					
Japan	515	700	860	4.4	744	744
Korea	124	190	240	5.7	77	177
Taiwan	84	154	198	7.4	132	132*
Hong Kong	neg.	neg.	neg.	-	0	0
ASEAN Countries	neg.	neg.	neg.	-	0	0

* Additional facilities expected.

The acrylonitrile market on the West Coast is very small, and markets in the Far East are anticipated to grow modestly, with the region being generally self-sufficient in the product. As a result, there is little opportunity for large acrylonitrile exports from an Alaskan facility, and a plant would not be viable.

AGO 559725

L. Isopropyl Alcohol

1. West Coast Market

a. Demand

Isopropyl alcohol consumption in 1978 in the Western region totaled 165 million pounds, of which about 100 million was used captively for acetone production by Shell. Isopropanol is used in chemical extraction, pharmaceuticals and coatings. Some isopropanol is sold for use in its own right as an alcohol. The breakdown of isopropanol use is shown in Table IV-L-1.

TABLE IV-L-1

WEST COAST ISOPROPANOL DEMAND
(Million Pounds)

Western U.S.	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
Acetone	120	100	100	100	104	-
Other uses and export	55	60	71	90	106	-
Total Western U.S.	175	160	171	190	210	2.3
Western Canada	5	5	6	8	10	5.7
Total	180	165	177	198	220	2.4

Acetone is the largest use for isopropanol, consuming 100 million pounds in 1978. Very little growth in demand is expected over the 1978-1990 period due to capacity limitations of the Shell unit.

Coatings and solvent still provide a large market for isopropanol; they account for over half of the "other" uses. Oils, gums, shellac and synthetic resins are typical solvent uses. One significant chemical use is the extraction of pectin from rind. Pharmaceuticals and various miscellaneous uses account for the remaining use of isopropanol in the West Coast region.

b. Supply

There is only one producer of isopropanol in the West. Shell has a 215 million pound plant in Dominguez, California. Shell has most of the market, with Exxon and others also supplying the area. Shell, Van Waters & Rogers and Shore-Line Engineering distribute in Western Canada.

c. Captive Market

The only captive consumption on the West Coast is Shell's use of isopropanol for acetone production. This use will remain at about 100 million pounds per year over the study period unless increased by-product acetone in available from a new phenol plant.

d. Pricing

The price for anhydrous isopropyl alcohol in the U.S. was $1.25 per gallon as of October 1, 1979. The Canadian price in late September was $0.243 (Canadian) per pound in the east, with prices somewhat higher in the west. Canadian imports of isopropyl alcohol are subject to an 8 percent ad valorem duty.

2. Pacific Basin Region

a. Japan

Isopropanol demand in Japan is relatively modest since very little is used for the production of acetone. Overall demand is anticipated to have modest but continued growth over the study period, with demand increasing from 75,000 metric tons in 1978 to 100,000 metric tons by 1990, as shown in Table IV-L-2.

TABLE IV-L-2

JAPANESE ISOPROPANOL DEMAND
(Million Pounds)

	1977	1978	1980	1985	1990	AAGR, % (1978-1990)
Solvent	31	32	33	36	39	1.7
Agricultural chemicals	5	5	6	8	10	-
Medical uses	5	5	6	8	10	-
Surfactants	5	5	6	8	10	-
Chemical manufacture	3	3	4	5	6	-
Miscellaneous	13	15	16	18	20	-
Total domestic demand	62	65	71	83	95	3.2
Exports	10	10	9	7	5	-
Total demand	72	75	80	90	100	2.4

Supply

Japanese producers of isopropanol are listed in Table IV-L-3. Existing isopropanol capacity is 105,000 metric tons per year. There are no expansions in progress, but Tokuyama Soda has considered a 15,000 metric ton per year expansion. It is anticipated that supply of isopropanol will be sufficient to meet Japanese and some export demand.

TABLE IV-L-3

JAPANESE ISOPROPANOL PRODUCERS, 1978
(Thousand Metric Tons per Year)

Company	Location	Capacity
Mitsui-Toatsu	Senpoku	30
Nippon Petrochemical	Kawasaki	60
Tokuyama Soda	Tokuyama	15
		105

Pricing

The Japanese isopropyl alcohol price was 160 yen per kilo (33 cents per pound) in early August 1979. Isopropyl alcohol imports are subject to an 8 percent ad valorem duty.

b. Korea

Demand for isopropanol in Korea is modest, with demand for this material expected to remain under 2,000-3,000 metric tons per year throughout the study period.

c. Taiwan

In 1978, isopropanol demand in Taiwan was estimated at or near 1,000 metric tons. Demand is expected to reach over 2,000 metric tons by 1990 in existing applications. The major use for the product is in cosmetics and toilet goods.

At present, isopropanol is not produced in Taiwan. A 30,000 metric ton per year isopropanol unit has been planned as part of the fourth petrochemical complex and is expected on stream about 1983. The material would be used for acetone manufacture.

d. Hong Kong

Hong Kong consumption of isopropanol in 1978 was about 1,700 metric tons. Consumption of this material is forecast to grow 6-8 percent per year over the study period. There is no production of isopropanol in the Colony and none is anticipated.

e. ASEAN Countries

Demand for isopropanol in the ASEAN countries is expected to increase from 7,000 metric tons in 1978 to 15,000 metric tons in 1990, as shown in Table IV-L-4.

TABLE IV-L-4

ASEAN COUNTRY ISOPROPANOL DEMAND
(Thousand Metric Tons)

1977	6.5
1978	7
1980	8
1985	11
1990	15
AAGR (base 1978), %	6.6

The Philippines accounts for about half of isopropanol demand. Imports for Singapore, Malaysia and Indonesia, which are handled through Singapore, account for most of the remaining consumption.

There are no isopropanol facilities in the ASEAN countries and none are expected throughout the study period.

f. People's Republic of China

PRC isopropyl alcohol imports are insignificant.

3. Conclusions

Opportunities for an Alaskan Plant

The supply and demand for isopropyl alcohol on the West Coast and in the Pacific Basin are summarized in Table IV-L-5.

Since there is sufficient capacity to meet forecast demand during the study period throughout the Pacific Basin countries, an isopropyl alcohol plant in Alaska is not viable.

TABLE IV-L-5

ISOPROPYL ALCOHOL

	Demand				Capacity, per year	
	1978	1985	1990	AAGR, %	1978	Future
	(Million Pounds)					
West Coast	165	198	220	2.4	215	215
	(Thousand Metric Tons)					
Japan	65	83	95	3.2	105	105
Korea	2	3	3	-	0	0
Taiwan	1	32	32	-	0	30
Hong Kong	2	3	4	-	0	0
ASEAN Countries	7	11	15	6.6	0	0

M. Propylene

Propylene is normally consumed in derivative plants at or near the production site. However, Korea has been a significant importer due to a supply/demand imbalance, but all other countries have sufficient propylene or have imported the product in the form of derivatives. The imbalance in Korea is not anticipated to continue, since new sources of supply will come on stream in the early 1980s. It has been proposed that propylene be imported as feedstock for a new polypropylene plant in the Philippines. Requirements would be about 150 million pounds per year. At present, however, it is uncertain if this project will proceed.

Over the longer term, it is expected that propylene will be in surplus in the Pacific Rim area and, as a result, no significant propylene markets exist for production from an Alaskan facility.

V. FEASIBILITY OF AN ALASKAN PETROCHEMICAL COMPLEX

The core of a natural gas liquids-based petrochemical complex is an olefins plant which produces ethylene as the prime product. The simplest and lowest cost olefin units are based on ethane feed. If propane and/or butane are used instead, significant quantities of propylene are also produced.

For a petrochemical complex to be viable, a sufficient volume of derivatives must be produced to utilize the production from a world-scale olefins unit. The economic size is at least 1 billion pounds per year of ethylene capacity.

As shown in the analyses presented in Section IV, the manufacture of low and high density polyethylene, styrene, vinyl chloride and ethylene glycol in world-scale units were found to be viable. Table V-1 summarizes the potential ethylene consumption by derivative.

TABLE V-1

POTENTIAL ETHYLENE CONSUMPTION BY DERIVATIVE
(Million Pounds Per Year)

Derivative	Derivative Plant Size	Ethylene Consumption at Capacity
Low density polyethylene	500	525
High density polyethylene	250-400	260-420
Styrene	600-800	200-270
Vinyl chloride	500-1,000	250-500
Ethylene glycol	400-500	320-400
		1,555-2,115

Based on the market situations, an Alaskan petrochemical complex would most likely consist of low and high density polyethylene facilities, plus a styrene, vinyl chloride, or ethylene glycol plant. The choice of units would primarily be dictated by the nature of the firms involved in the project.

The market for propylene derivatives does not look very good. However, if it were necessary to use propane and/or butanes as part of the feed, a 200 million pound per year polypropylene plant would probably be viable.

Basically, the petrochemical markets in the Pacific Rim area are sufficient to support a major complex in Alaska at present and probably a second complex in the late 1980s.

AGO 559734

scomm

#14:17

Alaska State Legislature

POUCH Y, STATE CAPITOL
JUNEAU, ALASKA 99811
907 465-3800

TRANSCRIPT OF TESTIMONY OF

DR. ARLON TUSSING

March 16, 1978

BEFORE THE SPECIAL COMMITTEE ON ROYALTY OIL AND GAS

Committee:

Senators:	Representatives:
Chairman Mike Colletta	Chairman Bill Miles
Pat Rodey	Chat Chatterton
Bill Sumner	Joe McKinnon
John Sackett	Charlie Parr
Kay Poland	Al Osterback

DR. TUSSING:

You all know who I am, and I won't waste time on introducing myself. I have a number of questions I intend to address myself to this evening, and let me run through the questions which I would deal with, if I have the time, which I won't, and we'll try to be selective. What I'll do is I'll take up one issue at a time, and let you discuss....let's have some interchange during the discussion. I won't have a formal presentation. We'll just take these issues up. Feel free to interrupt me if there is something you are not following.

Here are the issues that had been identified as possible areas for my treatment on which I'm ready to comment. First, what is the likelihood that the ALPETCO project will be commercially viable? And under that, comment on the Alaska disadvantage and how ALPETCO might overcome it. Second, comment on the realism of ALPETCO's marketing plans for Japan and for the U. S. West Coast. Third, is it possible, or likely, ALPETCO could get its project financed without an overwhelming assurance of its commercial feasibility? Fourth, what would happen if the ALPETCO facility were financed and built and, after its completion, it were to be unprofitable? What would be the consequences for ALPETCO's sponsors, for the bond holders,

AGO 559735

for the employees, for the community in which the plant was located, and for the State? Fifth, if ALPETCO were to encounter difficulties, either in financing the project or in operating it profitably, what other assistance, if any, would ALPETCO be likely to ask from the State, apart from a discount on crude oil prices? What would be the cost risks or other implications for the State from any of these measures? Sixth, what will be the likely impact of the ALPETCO project on the West Coast oil market and on the value of Alaska crude oil generally, both before and after the proposed facility goes on-stream. Seventh, comment on Sections 2.3 and 2.4 of the contract, specifically the option to buy non-Prudhoe royalty oil. Seven, comment on the procedures by which the Commissioner of Natural Resources and the Royalty Board decided to negotiate this contract. And eight, how can the Legislature best resolve the factual, legal, analytical, and policy questions presented by this contract.

Of all of these things, I think that the Battelle presentation has set the background for discussing some of the issues which relate to the West Coast surplus. Firstly, let me say that the West Coast surplus will have, and is having, a consequence that the Battelle study did not point up and that is in exerting downward pressures on West Coast oil prices. And, as the West Coast surplus increases, those downward pressures will increase. I will want to show you in a brief scheme how these downward pressures are likely to work.

Taking a series of hypothetical prices at Valdez - these are net back prices at Valdez for shipments to various parts to various markets based upon what net back prices were posted by the company in September of 1977, with some modifications, but, essentially, the sales in Alaska to Alaska refiners were at $12.50 a barrel; that is, as of Valdez. West Coast sales were at an average of $12.63. Gulf Coast sales were at $10.72. And this reflects the differences in transportation costs to those markets, as the average transportation cost from Valdez to the Gulf Coast was $3.05, while the average transportation cost to California was $.82, and to Cherry Point $.60. And this is what results in the difference in Valdez price.

Okay, now let's move forward to 1980 and assume that nothing changes in terms of the real prices of oil, that the OPEC price in real dollars, remains constant, and the transportation costs remain constant. And that, of course, assumes that for the Gulf Coast price to remain constant and assumes there will be no higher prices.

CHAIRMAN MILES:

Doctor, are you sure that your figures are right there - $12.50

AGO 559736

at Valdez price for sale in Alaska and a higher sale for the West Coast?

DR. TUSSING:

Yes. I'm not sure these are right. I took this figure from Bonner and Moore, who claim to have derived it from state revenue figures. Since I had just one day to prepare this, I had to grab the only materials I had at hand. I didn't have a chance to go to the original data. Whether or not this is precisely right is irrelevant to the thrust of my explanation. What I am dealing with is the large difference between the West Coast and the Gulf Coast net back, and Battelle set out the same thing. They had different numbers, but they were in the same order of magnitude - roughly, a $2.00 difference in the net back price from the West Coast and the Gulf Coast.

As you know, ARCO was able to market most of the oil through its own West Coast refineries; EXXON, a somewhat smaller proportion; and SOHIO, with no outlets of their own on the West Coast, must ship most of their crude to the Gulf Coast markets. Now projecting ahead the shares of the various markets to 1980, and assuming 1.2 million barrels per day, which is more than is going to be produced at this stage - but, again, it's a minor....I'm not trying to predict the future in this - but, projecting the differences, we have for ARCO an average net back price at Valdez of $12.23, for SOHIO, an average net back price of $12.21 - not for SOHIO....for EXXON, SOHIO - $11.46, and for a total, including the other minor companies, a weighted average price of $11.79.

Alright, now, what we see here is that the cost of oil for SOHIO is more than a dollar under the West Coast price. It's an interesting situation, which in our competitive textbook economics would say would not last very long because SOHIO, rather than accept this price for its oil, would want to penetrate this market for every barrel, additional barrel, that SOHIO could put into the West Coast market. SOHIO would make $1.17 more. Our textbook market economics would say SOHIO would keep trying to sell oil on the West Coast until - what would happen if SOHIO tried to sell more oil out on the West Coast? They would drive this price down. In other words, to make room in the market, they would have to offer a discount because ARCO and EXXON are selling all they can at this price, or moving all they can at this price - the biggest customer is SOCAL - to displace more Saudi crude out of SOCAL's supply, or, for that matter, to convince refiners to not to take oil somebody else. So, SOHIO would have to offer a discount. Now, SOHIO would be ahead as long as it could get more than $11.46; that is, on the last barrel. The reason SOHIO doesn't do this is that by pushing more crude into the West Coast they are not just making....suppose they offer it on the West Coast for

AGO 559737

$11.63, for a dollar discount. Well, they are making the difference between $11.46 and $11.63 on that incremental barrel, but, in the meanwhile, they are provoking the others to cut their prices, too, to maintain their market share. The California independents will cut their prices to maintain their market share. So, all the producers would end up worse off than they were before, as they would all end up selling roughly the same amount of oil into the West Coast market. But all of them would be getting less, and the state would be getting less. So, SOHIO, because it's such a big element in the market, suffers most from its own competitive actions. SOHIO is not about to start a price war which will drive the West Coast price down.

Other than that, with the growing surplus, SOHIO really does want to market this. One of the things that came out in the suit of the Maritime Unions against the Virgin Island Exchanges - what was doing was SOHIO was swapping its oil with SOCAL; it was delivering its oil to SOCAL and taking SOCAL's Saudi crude and selling the Saudi crude in the Virgin Islands at a discount. They weren't discounting on the West Coast. They were posting their net back prices in Alaska as if they were selling it in competition with Saudi crude on the West Coast. Yet, they were taking a loss on the Saudi crude they sold in the Virgin Islands. So, in effect, they were discounting without it appearing on the books, and the State of Alaska was getting royalties and severance taxes on the basis of a crude price which was higher than the true value - the market value - of the crude. In other words, SOHIO was willing to pay a higher royalty and a higher tax than it had to, based on the true value of the crude in order not to appear to be pushing down the West Coast price.

This was what was happening with production at less than 700 million barrels a day - 700 thousand barrels a day. As production gets up to 1.1, the downward pressure of the temptation of any of the producers to try to get more of the West Coast market. All of them can do better on the West Coast than they can.... Their average price is lower than the West Coast price. They can all do better so long as that's the case.

Now, if competition broke out, what would happen is the West Coast price would be driven down to $10.72. The competition that each of these producers, say SOHIO, would keep trying to sell more oil on the West Coast. It could keep making more oil on the incremental barrel, on the last barrel, by selling it on the West Coast at a discount until they got it down to this price.- until they were making no more from selling on the West Coast than they made on the East Coast. If they could receive $10.73 by selling an extra barrel on the West Coast, instead of $10.72 by selling on the Gulf Coast, they would do it, if there were competition. Now, where does ALPETCO come

into this?

In a situation where the surplus is going to be increasing, at least until 1985, and I suspect it's going to continue to increase faster than that - the projections that were cited by Battelle that show it falling off are both pessimistic about future discoveries. By 1985 we are going to have the (indisc.) Sea sale, the lower Cook Inlet sale - will have been taken place long enough that if there are any discoveries to be made there they will ready to go on-stream. There will be, according to the Interior Department's schedule, seven more OCS leases off Alaska in that time, so that the supply may continue to expand far beyond the highest of those projections. While it's my belief we are in for a long period of low economic growth and low increase in energy demand, for reasons which you can see.

Now the economic management of the United States and the Free World is not really at its optimum, and I think that we're going to see very low rates of growth - of economic growth and energy growth, generally. So, we're going to have an increasing surplus on the West Coast, increasing downward pressure on prices if exports aren't authorized and if none of these proposed transcontinental pipelines are authorized. And I think the odds are against all of them. Anyway, you have continued downward pressure.

What does ALPETCO do? If it comes in as a petrochemical plant, it removes some of the surplus crude that otherwise tends to depress the West Coast price. It does not go into the petroleum market as such. And so a crude-base petrochemical facility in Alaska, or anywhere on the West Coast, if it used Alaska-type crudes, would reduce the surplus of crude on the West Coast, it would reduce the amount which has to be pushed through to the Gulf Coast. The weighted average price, the price that ALPETCO would have to pay under these assumptions, would be $11.79. They would be paying $11.79 essentially for oil that would otherwise have to be marketed on the Gulf Coast for $10.72. So there would be two effects of that. One is that the pressure on the part of the other producers to market their surplus on the West Coast, and drive down the price, will be reduced. The second is that the weighted average itself will tend to go up because some of this will be pulled out. Some of the $10.72 will be pulled out of the weighted average and replaced.... say, this is oil that SOHIO pays $10.72 for, will be reduced.... and, instead, ALPETCO will be paying the $11.79. So the weighted average will go up, and ALPETCO's price will be more than $11.79.

So everybody's price will be....the total price will be higher. So, (indisc.) in that context, any facility which removes oil from the West Coast market and reduces the pressures on the West Coast market, the surplus is favorable to the state. Now, as the Battelle people pointed out, the thing that is over-

whelmingly most favorable to the state would be exports to Japan. I think that they made a good case that this is the best thing, under any circumstances, that could happen to the state. I think that the state has not devoted it the attention it might have to overcome the political bottlenecks. This is something that is a subject for another discussion, but I believe that exports could be authorized with the proper political strategy.

But, getting back to this.... Second best would be a petrochemical plant as opposed, say, to a products refinery which would simply push more oil into a West Coast market that's got more oil in. Now, (indisc.) from the petrochemical plant, however, to the ALPETCO proposal as a whole, there is another problem and one sees another picture. The proposed contract entitles ALPETCO to take up to 150,000 barrels, or up to its full Prudhoe Bay entitlement, of crude oil for re-sale up until the time their plant is ready to use it. Let's see what the effect of their taking that oil in (indisc.) will be. According to their pro forma financial statements, they intend to market their oil on the West Coast of the United States, and they intend to mark it up by two percent. Then they expect to earn a two percent margin on it and they give a puchase price of $7.00 at the well head, plus shipping costs to the West Coast of $.85, plus an ALPETCO margin of $.25, and tax (indisc.) for $5.40, and give a $13.50 sales price on the West Coast. Well now they're starting with different numbers - and I won't quarrel with those, because they are based on other assumptions as to what the actual tax tariff will be and what the net back will be. But the problem here is ALPETCO takes oil that costs the $11.79 at Valdez, that is, well head price plus tax tariff, and there is no way that it can sell it on the Gulf Coast. ALPETCO gets 150,000 barrels, 140,000 barrels, of oil for $11.79. They lose money unless they can sell it for $10.72 plus transportation to the Gulf Coast, which is $3.00. So there is no way that ALPETCO can consider marketing on the Gulf Coast. ALPETCO, if it takes this oil, has to go into the West Coast. What can ALPETCO afford to do? ALPETCO says that it is looking for a two percent margin, so that brings its price at Valdez to $12.03. And, in that case, they can undersell the West Coast price by $.60. In other words, the value of North Slope crude oil on the West Coast as set by what the other producers are charging is $12.63. ALPETCO is getting its oil and is willing to sell oil for $12.60. I mean $12.03.

I really doubt whether, out of roughly 6 to 700,000 barrels per day of Alaska crude, which can be marketed on the West Coast, they are going to push in 130 or 140,000 barrels a day of it for only a $.60 discount. If you recall, ARCO will be moving all of its own oil through its own refineries. There is no way they could push ARCO's crude out of ARCO's refineries. EXXON

is going to be running a substantial amount of its own crude in its own refineries. Essentially, if ALPETCO is going to market this, they are going to have pretty much mop up the independent refiners who could accept the backing out of a very large portion of California independent production. And they are going to have to butt heads with SOHIO. They are going to have to undersell SOHIO at the CHEVRON refinery. Let's go back, There is no way they can sell Alaska royalty oil on the Gulf Coast. The only way they can sell it on the West Coast is to undersell SOHIO. And, essentially, they've got to undersell SOHIO at CHEVRON's refinery.

CHAIRMAN MILES:

Why would a CHEVRON refinery, an independent refinery, be willing to strike a temporary agreement with ALPETCO when they know that essentially they are going to have to go back to producers once the proposed facility starts producing petrochemicals?

DR. TUSSING:

Because there's a surplus of oil.

CHAIRMAN MILES:

Simply because of this?

DR. TUSSING:

Well, if you had a seller's market, which you don't have now and you won't have in 1980, and, very likely, you won't have in 1985. You certainly will have a buyer's market on the West Coast of the United States, at least through 1985. They are going to shop around.

Now, I'm not saying that the process is going to be perfectly competitive just because there's one seller. But now we've got a wild card in the deck. We have a different kind of seller. SOHIO will not behave competitively, will not use its full market power to capture its maximum market share on the West Coast because it knows it's spoiling its own market.

ALPETCO's in a different position, because to the extent ALPETCO drives down the West Coast price and can make a profit in doing so. Next month the composite average goes down if ALPETCO sells for $12.03. You can see SOHIO's getting their oil cheaper than ALPETCO is. SOHIO can defend its market position. SOHIO will not initiate a price war, but SOHIO will not be backed out, either. So SOHIO will go as low as ALPETCO can go, and it can go lower for the purpose of protecting its market

share. Some of the California independents can't. And you're having this problem right now that Alaska oil is backing out California independent production. The Economic Regulatory Administration just gave an additional $1.79 entitlement benefit, or reduced the entitlement penalty, for the California producers by $1.79. And, thus, oil is still backing up California production. So those people, some of them can't back down. Some of them will make room for additional North Slope production, but you bet they will be in Washington and trying to get some new entitlements (indisc. - cough) or some other thing that prevents them from being backed out.

So, if ALPETCO can't afford to drive the West Coast price down to $12.03 and still make money. Unlike SOHIO, unlike ARCO, and unlike EXXON, they don't lose a penny by doing it, because they have no stake in the production of the rest. They have no production. They are a middle-man. And, to get this market share, they will go in and compete - they will engage in what textbook economics calls arbitrage (ph). And they will make their two percent, or they will make more than two percent on the arbitrage (ph). They don't have to take the full 150,000 barrels at once. They can start with a minimum of 10,000 barrels. You find a home for 10,000 barrels today. Give me 10,000 barrels of oil today at the composite average price, and I can find a home for it in California at $12.00. No question. I can find some California crude, or some SOHIO crude, that I can back out. So you take that next month. Meanwhile, you have driven this down a little bit and you've got a greater price advantage. Where does the process end?

If this becomes $12.03 - the West Coast net back price becomes $12.03 - the in-value price becomes $11.48, and here we get another round. And, so, where the process ends....it probably won't go all the way, but the only place that brings it to a definitive halt is when the West Coast price gets down to $10.72, which is the competitive equilibrium price. That is what your textbook economics would say is the natural price. That is the value of North Slope crude oil on the West Coast. Because, why should any producer on the West Coast accept this price, ship it to the Gulf Coast, and take a lower price if they could sell it for even a penny more on the West Coast? So the end of the process is this.

People tell me, or I have been told by people who are in these negotiations, that ALPETCO has no intention of taking this oil and marketing it. I know that Sea Train (ph) and Alaska Consolidated Shipping, which was the predecessor organization, had this as the main thrust of their participation, and they were most interested in getting an option on the royalty oil for the purpose of marketing. Now, I'm not urging any, or suggesting there's any bad faith here, I see no evidence that

any of the ALPETCO participants have ever thought this through. I know when I was on the Royalty Board the submissions (indisc.) asked of Consolidated Shipping, with respect to their proposal, were totally unrealistic because they were expecting to take oil at the in-value price and sell it on the Gulf Coast. They had professed letters of intent from purchasers on the Gulf Coast; they gave this as evidence they could do it, saying that we would take it at a price no higher than the lowest price at Prudhoe plus transportation cost.

Anyway, I don't know what their intentions are, and we'll get to how I think that the Committee ought to proceed in looking at some of these things a little later. But I can tell you that....with confidence, that just as Battelle sets out the case it would be a disaster for the state to market its own royalty crude oil, for the same reason, and perhaps even more so, a disaster if you let somebody like ALPETCO market the state's crude oil. The West Coast consumer will benefit, the national economic efficiency will benefit, but the tendency is to introduce into that market a major seller who has no stake in the business of an orderly market, who is not an oligopoly, profit maximizer.

Now, this moves on to something else. Let me put my statement to the Royalty Board in the record at some point. At that time I'd be reported on a survey I did for the Commission, mainly on the realism of ALPETCO's plans for marketing in Japan.

CHAIRMAN MILES:

Representative Chatterton.

MR. CHATTERTON:

Thank you, Mr. Chairman.

Doctor, did you say you wanted to....were willing to be interrupted before you switched to another subject?

DR. TUSSING:

Yes. Surely.

MR. CHATTERTON:

I have one question of you. This exercise we have gone through.... I think it's great, but aren't you analyzing just a small portion of the total system and not analyzing the system? Is not, with about 14 million barrels a day producible capacity today that Saudi Arabia has, and yet they're only producing about

8.7 million barrels per day....don't you think that they are the ones that control the West Coast price and not SOHIO? If you look at the total system?

DR. TUSSING:

If you look at the total system you see who controls the level of world prices. But the prices in individual markets vary according to transportation arrangements and local supply-demand situations. The Saudis control the price at the North Slope. If Saudis decide to cut back further on production to raise the OPEC price, the net back at the North Slope will go up. But it's not true from that to say the tax tariff doesn't determine the price on the North Slope. So, here you've got the OPEC price here at this level and, depending on the distance from Saudi Arabia and from the Persian Gulf, you'll have prices in various markets in the world like this - prices at the refineries. And then there will be other places that feed into these refineries, and you'll have to subtract transportation costs from the price there. This is the.... If this is the West Coast price, then the transportation cost from Prudhoe Bay to the West Coast influences the West Coast price. Now suppose Prudhoe Bay, plus California, put in more oil than the California can use - than the West Coast can use. That, in a sense, begins to free it from the OPEC price, because California is no longer importing OPEC oil. The only way that Calfornia price is determined by OPEC is - what is the transportation cost beyond California to the next market, which is the Gulf Coast, or to Japan? That is, it's the OPEC price in a third market that then begins to determine the Prudhoe price.

So, yes, it's true. OPEC moves the whole structure up and down. But what goes on on the West Coast of the United States determines whether this is wide or narrow and determines whether the West Coast price is above or below the OPEC price. I think it is inevitable, as long as there's a surplus on the West Coast, that the West Coast price, particularly for middle-sulfur, middle-gravity crude oil, like Prudhoe Bay crude oil, will be below the OPEC plus transportation. It's got to stay below that or we won't even absorb all the North Slope and California crude. The price situation can't be such that refiners are indifferent to whether they use Saudi twenty-seven degree, one percent sulfur crude or North Slope twenty-seven degree, one percent sulfur crude. So the West Coast price is going to be lower than the OPEC price for as long as we can forecast in the future.

I think that Battelle is reasonable in saying, we really don't want to forecast beyond 1985, because both supply and demand.... there are so many uncertainties in both supply and demand. The general concensus is that world oil prices are going to go down until some time in the 80's, and then they'll start

turning up again some time in the 80's, but there's enormous disagreement about when that is. Some....the C.I.A. and Dr. Schlessinger (ph) and EXXON say 1982, there are other people who say that the crunch is like the horizon, as you get close to it it recedes because the geologists and the government officials have always, historically always, underestimated the new discoveries. The Paley (ph) Commission in 1946 had us running out of oil by 1949, the Geological Survey had us - in 1921 - running out in before 1929. That's why they set up the Naval Petroleum Reserve in Alaska, so the battleships would have some oil to run on in World War II.

Anyway, up to 1985, the West Coast price is going to be below the OPEC price - how much below the OPEC price depends on the market behavior of the producers and sellers on the West Coast, among other things. If the oil is closely held and flows through controlled channels - the North Slope oil is controlled overwhelmingly by ARCO, EXXON, and SOHIO - the effect of competition is going to be minimum. They don't have to violate anti-trust laws, they just have to behave like gentlemen toward each other. They just have to avoid getting into price wars that they know would be mutually ruinous.

The state royalty oil sold to an independent marketer has no such constraint. And, if one of the non-majors came in with a discovery out in the Western Arctic, or something like that, and it was somebody who was not tied in by intimate relationships with the (indisc.) agreement, and things like that, somebody came in with a large field - it could be Occidental, or even a major - Texaco or Gulf - they could break the market, too. Let's say that if ALPETCO attempts to move 150,000 barrels to the West Coast market, they are almost certain to break the market, and the bottom is somewhere in the vicinity of $2.00 below the present price. Now it won't hit bottom. Maybe the SOHIO pipeline will be built which would mean the bottom would be in the vicinity of $1.25 below the present price.

MR. GRUENING:

Does that mean that this is money that ALPETCO is going to lose if forced to sell it, so this is money to pay the state if, supposedly, they lose? Let's say they lost $1.00 a barrel, and it takes seventy-two months, I think in the contract, before they are actually putting it in a form where it could be sold. But, as a refined product, you're talking about over $300 million.

DR. TUSSING:

They don't lose any money. They sell it at above cost. Their cost is $11.79. When it first comes in they can sell it on

the West Coast. The West Coast refiners are paying $12.63 for that kind of oil.

MR. GRUENING:

You're saying that they won't prolong if they get....

DR. TUSSING:

Okay. Now the question is....the contract does not compel them to refine in Alaska or to process into petrochemicals any specific amount. So they don't reach full production. In their pro forma, their financial statement, they assume that they reach full capacity of 150,000 barrels a day in the fourth quarter of 1985. There is nothing that prevents them from continuing to sell. Suppose their petrochemical production contract is slower, and suppose they are making a good deal of money on these West Coast.... There is nothing in the contract that compels them to refine all that oil.

Now, I'm not trying to predict what they are going to do, because they don't know. I'm sure if you asked them, they'd say - well, these are the projections we're working on, but we don't know what markets will be like; we haven't even got our products laid down. But I would say, in general, that the existence of a crude-based petrochemical facility benefits Alaska in terms of the tax and royalty (indisc.).

An independent marketer very much hurts Alaska. It cannot do anything but hurt the state, and the state would be much better off to say - we'll keep the oil until you go on-stream, but we'll pay the two percent margin that you expected to earn on it. Let's just give them the money and let the producers.... The state would be far better off just handing them the two percent outright.

Okay. Well, let's go on and get back to the Alaska disadvantage. You've all heard about the Alaska disadvantage. I don't need to repeat it. You've got transportation cost disadvantages, higher construction costs, higher operating costs. And virtually everybody in the business, whether it's in the oil business or the chemical business, except this group, believes the Alaska disadvantage can't be overcome without some sort of subsidy. Now this group believes that....ALPETCO believes that it can.

I haven't worked through their economic analysis, and I don't know. I just know that it's a minority point of view. It's virtually a minority of one....

UNIDENTIFIED SPEAKER:

You've been there before.

DR. TUSSING:

No, I'm not the minority. I'm with the majority. They are the minority of one. And even their marketing consultant at the Royalty Board agreed that Joe Moore's assessment of the probability of success is fifty percent, at best - agreed that that was a fair assessment. Let's say they are going against the entire weight of industry sentiment, and I won't quarrel with that. But there is an Alaska disadvantage. Now, how can it be overcome?

The marketing plan we talked about has two elements. One is the expectation of getting long-term, hell or high-water, take or bake contracts from Japanese chemical consumers - Japanese industry. I did an investigation of this for the Commissioner and found no reason whatever to believe that there was any possibility that they would accomplish that, and I would say that the odds on that part of their program are - maybe they are finite - very close to zilch. Now it is conceivable that the notion that they can market on the West Coast....there is a substantial possibility that, given their cost structure, they can market on the West Coast. There is no basic petrochemical-producing facility on the West Coast.

Given any reasonable assumptions about economic growth, the demand will increase, and there is a gap that they could fill if they could overcome the cost disadvantages of operating in Alaska. They realize that the alternative sources for the West Coast are, for example, the Gulf Coast - the expansion of the existing petrochemical industry there - and there is part of the cost disadvantage, the transportation cost disadvantage, the transportation cost component of the Alaska disadvantage, is offset by the fact that if that crude has to go to the Gulf Coast and the products come back to the West Coast. So a West Coast petrochemicals plant would have a substantial advantage for the West Coast market over the Gulf Coast. Now it's quite conceivable, even though a California-based petrochemical facility would be in better economic shape than an Alaska one, that because of air-quality problems, site problems, it may simply be impossible to get a site for a petrochemical plant in California. So given those two considerations, they might be able to offset on the West Coast a good portion of the Alaska disadvantage.

The remainder of the equation is an interesting one - that if the West Coast price for Alaska-type crudes were substantially below world market price, below the Gulf Coast price, if there were no SOHIO pipeline, if exports to Japan weren't allowed, then we'd have a price for a North Slope crew. There would be a price advantage for a West Coast producer, whether in Alaska

or in California of a dollar more per barrel over its competition in the Gulf Coast region or, for that matter, competition on a crude- or naphtha-based facility anywhere in the world. Here's where the marketing fits in, and, again, I don't believe this is ALPETCO's game plan. But, if by marketing crude independently between now and 1985 they broke the West Coast price, pushed it down to a level $2.00 below the world market equivalent, they would have gotten their subsidy from the state. They would have gotten that $2.00 by the back door. Now, why, when they go on-stream, doesn't the price go back up again? And that's an interesting question. Would it go back up when they take the crude out of the crude market and start marketing petrochemicals. I suspect it's a one-way downward rachet, because the equilibrium price - that is - the normal situation and the absence of some sort of anti-competitive behavior, is the same for all destinations at Valdez. And that the big three would have to collude, and they'd probably have to get the California independents on board. They would have to engage in per se violations of the anti-trust laws to re-establish the differential price structure. I think that once this differential price structure is knocked down by competition it would take a positive intervention - anti-competitive intervention - for the market to restore. So....

UNIDENTIFIED SPEAKER:

Dr. Tussing, just a moment. If we're talking about a time-frame of 1984-85, which is to unscrew their oil from the West Coast market, this is the time when the shortages, or the surpluses, appear to be diminishing. And if we further diminish it by 150,000, which is hypothetically injected into that under your scenario, doesn't that have to drive the price back up?

DR. TUSSING:

Well, as long as there's a surplus, there is no force driving the price back up; that is, there's a surplus now that is having downward pressure on the price. And that downward pressure is being resisted by the fact that the oil is moving in controlled channels. So long as the surplus exists, I don't think there can be any upward pressure on the price on a price structure that's been established previously by competition.

Secondly, I don't think we can count on, say, 1985 being the time in which the surplus is diminished. All we can do is say with confidence that the surplus will increase until 1985. After 1985 we don't know whether it will level off or diminish or what. So the.... I'm not trying to forecast the future.

I'm just.... The case I've established, with respect to the erosion of the price, is a worse case. As I said, I think there is a substantial possibility there will be some export outlet. For example, they could....the Federal Government could go half-way on it by allowing the export of residual oil from the West Coast. And it's the heavy high-sulfur resid which is creating a good deal of the glut. The top-end of the barrel can be used. If the California refiners could export their heavy fuel oil to the Far East, that would take a lot of.... There are things that would minimize the danger of the scenario, but the point I want to make is that the scenario which is worst for the state is best for ALPETCO in the sense that the best way of overcoming the Alaska disadvantage is with a lower price for crude. And that is one way I can see, without going dollar per dollar through their cost projections, and I'm not a chemical engineer or a cost engineer, and I can't assign costs to the various elements of their proposal, but just in broad general terms to overcome this cost differential, this is the only way I can see it working on the West Coast is they are relying on a West Coast price that's lower than the import equivalent price. And that is a way of overcoming the disadvantage. I want to repeat - I don't think that this is their game plan, because I've seen no evidence that there's been any long-term or any sophisticated view of the crude oil market on the part of their proponents. They certainly haven't put it on the record. And conversations with the participants over some time haven't betrayed any indication that this is what they are looking at. But I think that it is something the state really ought to take into consideration.

Now, if you have any more questions, I want to first ask how long you want to go.

UNIDENTIFIED SPEAKER:

I think we should just keep going.

DR. TUSSING:

Okay. One of the issues that was raised to me is....

UNIDENTIFIED SPEAKER:

Doctor, would you like to take a five-minute break?

DR. TUSSING:

Yes.

(FIVE-MINUTE BREAK)

AGO 559749

DR. TUSSING:

I think the most important of the remaining questions is.... two of them that go together - is it possible or likely ALPETCO could get its project financed without overwhelming assurance of its commercial feasibility? And I address this one, in particular, because I think there has been an assumption all along, and certainly Commissioner Leresche stated this, that the ability to finance the project is a good test of its commercial viability and, although we of the state can't make a really accurate assessment of it, the financial community will, and their ability to put the financing together is probably the best test of its commercial viability. I would think that would be the conventional wisdom, and I address the problem only because Milton Lipton said to you that it was not necessary to demonstrate overwhelming likelihood of commercial feasibility in order to get the thing financed. But it is quite conceivable the thing could get financed and still go belly-up. I don't think he was talking about the fact that bankers and underwriters sometimes make bad judgment, but I think he was saying that it's not necessary to show that it would be profitable to get the....to obtain long-term debt. And this is true with certain assumptions about financing, with what we call conventional financing, where there's a big equity component.

The financial markets, the bond underwriters, and the insurance companies, and the other institutional investors are not interested in the profitability of the project, per se. They could care less about the health of the equity of the owners. The health of the owners....the financial health of the owners concerns them only to the extent it affects the ability of the enterprise to pay interest and to re-pay the debt.

So, in conventional financing, if there is a sufficient equity component - that is, if the owners put up enough of their own capital - it's quite possible for them to get financing. In the worst case their cash flow is going to be sufficient to cover debt service. Suppose we're going fifty percent equity and fifty percent debt - I'll just use round numbers and not say....and I'm not going to claim these are the numbers of the ALPETCO project, but just to show the principle. Suppose you have a one-billion-dollar facility. So it's $500 million debt borrowed money. And the owner has put up $500 million in equity. Suppose the interest is nine percent, so it's got to pay $45 million here in interest. And it's got to pay.... Suppose it's got twenty-year life, and so it's got to pay $25 million a year in depreciation - in amortization - in debt repayment. All right, so you've got a total of $70 million that this company has to come up with in addition to its operating costs to pay off the debt. Now, to make money, to make it a worthwhile investment for the equity investors, they

AGO 559750

probably have to make fifteen or, say, twenty percent before taxes, at least. So it's probably twenty-five percent before taxes. So, to make it profitable, to make it worth doing, they have to come up with a cash flow of $195 million a year; that is, in profits, allowance for interest, and depreciation they have to come up with $195 million a year.

The equity investors probably won't go in unless they think they can make $195 million a year. They won't start the plant unless it shows on their pro forma statement that the cash flow is going to be $195 million. The bond sellers will go in, and they really have to be convinced that there is for sure going to be $70 million. And, if the $70 million is there, the owners could be losing money every year and they are still meeting their debt obligation. So it's true that a non-profitable....that the financial community is willing to invest in projects which may turn out....which have a good possibility of turning out not to be profitable and of pouring in money and lending money to PAN AM, or Penn Central, or God knows what. All sort of Chrysler companies lose money year after year after year after year. So long as there is some security, and they'll look at it in terms of the debt service coverage. They'll say.... They'll project the income and say the cash flow is how much percent of the debt service. Now, in evaluating utility bonds you look at what is their income as a multiple of the amount of interest and repayment they have to pay.

CHAIRMAN MILES:

Dr. Tussing, the equity owners aren't going to sit by and let that happen year after year after year.

DR. TUSSING:

What can they do? What can they do? They, most likely, have a situation, and this is true of many of these companies, this is true of Chrysler, for example, where they lose money year after year. They lose more by shutting down than they do by continuing to operate. They have to.... If they shut down they still have to pay that $70 million debt service. They still have those fixed costs.

If their revenues exceed their operating costs by even a penny, it pays to minimize your losses. And so, generally, when a facility is worth more as a going business, even to the trustees in bankruptcy.... Well, let's look at some numbers here. Suppose the fixed costs are $250 million a year and the variable costs, that is operating costs, are $250 million, so the total cost is $500 million. Okay, now....suppose your revenues, that is the sales, are $400 million with a loss of $100 million. What happens if you shut the plant down? You do away with

AGO 559751

$250 million operating costs. You reduce your costs by $250 million. You reduce your sales by $400 million. And so your loss goes from $100 million to $250 million. So what happens is these fixed costs include payments to bond holders, and so on, creditors. The same when you get the drain of $100 year after year and pretty soon the equity of owners is wiped out. And suppose they get to the point where they can't meet their....they can't pay their operating costs? The thing goes into bankruptcy. The bond holders become the owners. And they see this enterprise can't pay $250 million any more. What can it pay with sales of $400 million? All it can pay $150 million in interest and repayment. So, they take a bath on that, put the thing up for bid, and somebody buys it at a price which reflects this situation. That is, the old owners are wiped out, somebody comes in with a lower capitalization - he comes in owing less money - so he has to pay only this much.

First, in answer to the first question. With conventional financing it is possible to finance a project that has a large risk of losing money. And conventional financing is one where the owners either put up a substantial amount of equity or where this is a subsidiary corporation where the parent corporation, or somebody, is willing to guarantee the debt. So, to the first question....yes, with conventional financing where there's a substantial equity cushion, where even if the owners are losing money year after year, there's enough surplus revenue to pay the debt service. Yes, you can.

Second, in that sort of situation, the company can go on losing money for years and years and, as long as the owners, or the creditors, or the trustees in bankruptcy, or a potential other owner see that its sales are going to be more than its operating costs, it will continue operating. Now the owners may lose everything they've got, but it will continue operating. So, let's look at some of the consequences of this situation.

Suppose ALPETCO does get its financing together. Now, let's pass, for the time, on how they can do it, because they aren't proposing conventional financing. Suppose they do get the financing together and then they start losing money. Does that mean it's going to shut down....the plant is going to shut down and throw out the people who are working for it? Does it mean it can't pay its operating costs, which include the cost of feedstock, any more. No. Not so long as the sales exceed the operating costs. And in a capital-intensive operation of this sort, you really have to get into a bad situation before it pays to shut down or dump the plant before its value as scrapped is greater than its value as a going concern. So the chances of the state being compelled, from the point of view of keeping the jobs flowing, of bailing out a conventionally financed plant, are minimum.

I think the problem with ALPETCO is that its proposal is a little different. It proposes, rather than conventional financing, what is called project financing where the companies that own ALPETCO are putting up any their own faith in credit. They are not proposing to support the thing. So the bond holders have no recourse against Alaska interest. They can't take Anchorage Natural Gas; they have no recourse. They can't put a lien on Sea Train's ships, they can't put a lien on a native corporation's lands or future income, or anything of that sort. So, their only recourse is against the project itself. So they are going to look with even greater scrutiny than they would at the income statement and whether there is enough income to cover the debt service. Again, the problem here is that the owners don't propose to put up any capital. They propose one-hundred percent debt financing, or, if I read it correctly, there is something like a hundred....seven percent financing. When the thing goes on-stream the facility will have a negative net worth. That is, they will owe more than the plant is worth. And so the only security....the thing that they have to do, since there is no security in terms of an equity cushion, say all the cash flow has to be available for debt repayment - there is no equity cushion - they're not taking any bath, there's no recourse against the owners. Then what is absolutely essential is there be somebody that they can have recourse against. Well, I've convinced the Commissioner and his staff of adequately protecting the state against any legal recourse against the state, or against its revenues, or its royalty oil.

The only other alternative is that the sponsors get these take-or-pay, these iron-clad, hell-or-high water contracts where they have contracts with credit with the purchasers; that is, major chemical companies whose contracts are bankable. And these contracts may not have a fixed price, but they assure that have a....called hell-or-high water, or it's like the (indisc.) tariff we were talking about last year with respect to the gas pipeline where the purchasers have to promise, have to contract, to put up enough money, regardless of whether the plant is on-stream, whether it's producing, whether the producers are able to re-market the product to cover the debt service. Now it may be a formula price for the final price is determined by the world market price, or an index, or something like that. But there is no way that you are going to get institutional investors to go a hundred percent, or even seventy-five percent debt. In project financing, again, there's no recourse against the owners. Project financing....there's no way that the institutional investors will do that unless there are contracts that will provide for an assured revenue stream equal to the debt service charge - to the interest and amortization.

So, I'd say I don't know what Milton Lipton, what the assump-

tion of the questions to him, but I would say that the conventional wisdom is more right in this case; that is, that unless they can show the (indisc. - cough) that they've got contracts to sell the stuff, and contracts that are enforceable against credit-worthy purchases, then they are not going to be able to put it together. And I think that's what they've been saying....that ALPETCO's been saying all along. And their ability to finance the project is a measure of viability. If, for example, as against the conventional wisdom in the oil and chemical industry, and practically everybody I've talked to, going against that they are able to execute hell-or-high water contracts for the sale of their product, they will be financed. And they've got no marketability problem. They will be profitable because they have no equity to.... their rate of return on equity will be infinite regardless of how much money they make. So, if they can get it financed, they'll get it financed according to the plan here. If it's going to be project-financed a hundred percent debt, the only way they can do it with hell-or-high water contracts for most of their proposed output, and, if they've got that, they are home-free. They're not going to come back to the state and ask for special deals.

MR. PARR:

Dr. Tussing, what you are saying is if they have assured sale contracts....

DR. TUSSING:

Yes....

MR. PARR:

....they have an assured supply of raw material feedstock from the state, and they've got a physical plant, the bond holders aren't risking very much.

DR. TUSSING:

That's right. Well, they don't even have to have a physical plant. I think that they have to have the kind of hell-or-high water contract that as of such and such a date the purchasers will pay as if they were receiving the product even if they aren't. This is like (indisc.) Gas was proposing and El Paso was proposing for the pipeline financing; that the customers would start paying for the project and would start paying off the bond holders even if the thing were never finished. Say, they don't need the plant but they shouldn't have trouble getting the plant. They could run into cost overruns. That's a danger. And there are lots of scenarios in which I'd insist in coming back to the state for assistance.

And, if it were conventionally financed, the risks on the state would be minimal because that equity cushion would allow them to operate at a book loss for years and years without laying off employees or without needing to have a discount from the state.

I just don't see where they are going to get these contracts. And practically nobody I've talked to, except those associated with the project, think that they can do it. But I think the argument, and the approach of the administration, is what harm does it do to give them the chance? To give them a hunting license to go out and look for those contracts. If they can get the contracts, if they can get the financing, the state is ahead. If they can't, all we've lost is the time and the effort of the state officials and the Legislature in going over it.

MR. PARR:

Dr. Tussing, you said a minute ago that with conventional financing the state didn't have anything to worry about. By implication, one could assume that on this project financing we do. But, in actual fact, if isn't making it, the bond holders would take over to keep the operation running to get their money back. Isn't that correct?

DR. TUSSING:

Well, that's the most likely.

MR. PARR:

In other words, I'm thinking in terms of the loss of jobs and so forth and the dangers of (indisc.).

DR. TUSSING:

I don't want to say there is no danger of loss of jobs, because it is conceivable if we move into the middle 1980's with a big world surplus of petrochemical-producing facilities everybody else is going to be looking at operating costs, and we're going to have new plants on-stream in Saudi Arabia where they can back down the feedstock costs, where the Saudi government owns fifty percent of it. And, in order to minimize their losses, they're willing to cut back on the feedstock cost to cost of production, which may be forty cents per million B.T.U. or something like that. So, in that situation, you've got two things. Who's got the lowest operating costs, and this plant will certainly not have the lowest operating costs worldwide, and who's got the contractual market to share? Again, if the purchasers go on for twenty-year contracts, hell-or-high water, and the purchasers are credit worthy, they are

the biggest chemical companies in the United States or Japan, or wherever, then you really can't ask for better security and the dangers are normal commercial risks. I don't think there's any exceptional danger in it.

Now, on the other hand, let's look at some of the things that are likely to happen if they run into problems, if this group does not make its schedule. It's not going to roll over and play dead and say that well, sorry, that's the way.... you lose some....you lose a few, you win a few.

The first thing they're going to do, and they are going to do it whether they get into trouble or not, is they are going to go to municipalities or to the state and ask for industrial development bonds to finance their terminal facilities. It's ridiculous not to, because you can get a tax-free rate on.... and the City of Valdez did it with the terminal there.... And they can go to the City of Noorvik (ph), for that matter. It needn't be the City of Valdez, it needn't be where the terminal is, to get Noorvik (ph) to issue industrial development bonds rather than bonds which will be evaluated on the basis of the project. And they'll sell them the tax-free market. The City of Noorvik (ph) will get a fifty-thousand-dollar commission, or something like that. And, so, that's the first type of aid. Well, it seems to be costless unless the project goes belly-up. Unless it can't meet the bond obligation, the state has no legal obligation to come to the rescue of that, and it's just that Noorvik (ph) will never be able to sell any bonds again in the future, and the state will feel a moral obligation because if Noorvik (ph) defaults on $350 million dollars of industrial development bonds, it's going to affect the state's rate.

So, they're going to ask for that, and they're going to get it. They're going to find some jurisdiction in the state who will take the fifty thousand dollars. There's no question. And there's a certain amount of risk. For Noorvik (ph) if it couldn't be a better deal, or whatever, it couldn't be a better deal. They will ask for that, and they will get it. So, that's the first additional aid, and they are going to get that whether they get in trouble or not. There is no question in my mind they will.... I don't know - have you started talking to people about industrial development bonds?

CHAIRMAN MILES:

Anyone want to comment on that?

DR. TUSSING:

Well, maybe that's unfair....

CHAIRMAN MILES:

Yeah, I'd prefer to comment on all your (indisc.).

DR. TUSSING:

I don't know that they have, but they'll start soon enough.

What other assistance? Suppose they're just a tad from getting the financing together. They've got eighty-five percent of it. and you're going to be here like the Northwest Alaska pipeline. We need the back-stopping to put us over. After all, we have demonstrated that the benefits to the state are enormous. And, look, they are paying 10.9 percent interest on this last bit. The earnings on the permanent fund portfolio is 8.3 percent, something like that. If the state buys their bonds at 9 percent, or markets their bonds, or guarantees 15 percent of them for a commission, how can you lose?

Otherwise, we're going to lose this multi-billion-dollar project and all of these four-hundred, or four-thousand, jobs. And, so, it's an offer that's very, very hard to resist. It doesn't require.... If it's the permanent fund, the permanent fund managers look at this as a straight commercial decision. It meets the constitutional requirements for the permanent fund investments, and it will probably meet the statutory requirements. And it can be done without a vote of the Legislature and a vote of the people, unless the Legislature wants to say that no single investment of the permanent fund for certain.... But, that's the next thing.

Now, suppose the facility gets financed and gets into trouble. We have the same kind of thing. I'm not saying these are going to happen, but, you understand, the owners with their commitments are not going to, at some point, say well, we haven't made the schedule, or we haven't made the financing, or that's the way the ball bounces, or we're losing a million dollars a year - that's the way the ball bounces. And, so politically, they've signed a loyalty oath they're not going to ask for a reduction in the well head price, and there are certain moral commitments on the part of the state government to the people that they are not going to do it. So, how about re-financing? How about re-financing the thing? We're paying 10.9 percent. We can show....our pro forma shows that we'll break even. Otherwise we are going to be in bankruptcy and we're going to shut down, and so on. Would you....would the permanent fund re-finance our debt? Well, at that point we've bought the whole package and it's all sort of a re-finance (indisc.). This has happened time and again, not with these people, but with local industrial facilities. And I think if you haven't read the history of the (indisc.) Refinery in

AGO 559757

Newfoundland, there are some very disruptive....terrible. So, again, I don't know whether these risks are excessive. I haven't calculated the benefit to the state of this project. And if it went through, if the ALPETCO people's optimism is justified, the benefits would be significant. I don't deny that, and I don't condemn them for wanting to draw to an inside straight when the ante is so low in the pot and the pot is so big. But these are things you've got to consider.

One remark that might be a concluding one in this respect - what the significance of the whole project is. I believe that the Administration, that the Governor and Commissioner, have tried to give Alaska what the polls, and what the Alaska Forum, and what the Legislature has indicated the people want. That is, we want a petrochemical plant, but we don't want to pay for it.

All the assembled industrial wisdom, all the big oil companies, the big chemical companies, and all our consultants say they can't do it. It can't be done. Here you've got one company, one group of people, who says it can be done. So, why not give them a chance? That's fundamentally what the Administration's logic is. And, if you buy that logic, I think it's nit-picking to talk about the question of pledging undiscovered oil or the option on the rest of the royalty oil. We have nothing to give. All we have to give them is high costs, a horrible logistical place from the point of view of transportation costs - that's high labor costs, high construction costs, a god-awful climate that makes it harder to operate these things, and we've got some oil an assured supply of which is worth nothing now; that is, there is no premium for an assured supply. And these people are willing to come in.... I'm sorry they left, because (indisc. - laughter). They're willing to come in and gamble more time and money than the state has putting together this....I think it's pie-in-the-sky. They're willing to take a chance, and the Governor is saying to you well, what harm is it?

It is not true that it is a riskless contract. It's not true that it's a perfect contract given all things. But since we're unwilling to give them anything on outright, they're going to get every little fringe benefit they can. Nobody else has ever thought of the state furnishing them fill for the pipeline and the bottoms of the tanks. Well, we'll give them that. We'll give them the right to veto any other project we intend to use royalty oil for. But we read the fine print and we take it back, because it's on the same terms and conditions as the others. But we've given them a lot of things that seem like gold-plating. But, after all, we're not giving them anything else, and they've got all the odds against them.

So, if you want a petrochemical for cheap, for nothing, you probably won't get it with this contract. You probably won't get a better contract that's going to give you one. You've got a chance at it. As I said, I think the....giving them the right to sell royalty oil in advance of building a plant is dangerous. It's particularly dangerous, if, as is likely, the state's position on the value of oil is not upheld - the (indisc.) formula in the back of the contract does not prevail. Because the spread among prices is going to be greater.

But, other than that, and say you want something for nothing, you get what you pay for.

CHAIRMAN MILES:

Dr. Tussing, your most recent remarks seem to discount the fact....or discount it as being important the fact of an assured supply. We've heard quite contrary testimony to that. Could you go through your reasoning again on that?

DR. TUSSING:

Right now, and at least for the next five to eight years, there is a buyer's market in crude oil world-wide. There is an enormous surplus of crude oil-producing capacity. But right now nobody will pay a premium for an assured supply. A long-term contract is worth less than a short-term contract, because a long-term contract pins the buyer down to a single source of supply when it's in his advantage to shop around in this market. Now what the other people have been saying is that sometime in the future the world crude oil demand is going to overtake producing capacity, and supplies will get tight. And, as a hedge against that time, a supply contract going cut in the future may have some premium value.

Now, the present does reflect future expectations, but people give lip service to the value of an assured supply in the future but they're not willing to pay anything for it. And, again, that tells you whether they're really serious or not. You can....nobody will pay premium over the OPEC price to any of the OPEC countries in exchange for a secure supply. And, in fact, the OPEC countries have to accept a discount against the price to get a guaranteed long-term off-taker.

CHAIRMAN MILES:

Under that line of reasoning, though, it would seem that what you're saying is that it may be wise to delay this decision until the surplus is reduced or the shortage is intensified, however you might want to term it.

DR. TUSSING:

Well, the surplus may increase and the price go down. The thing is that ALPETCO is guaranteed against that if the price goes down with everybody elses. So you're not taking advantage.

Two years ago....three years ago people were panicked and they still remember the embargo, and you probably could have gotten a premium for a long-term supply, and you probably could have gotten.... In fact, I think the Alaska Petroleum Company, the Coastal State subsidiary, was willing to offer....two years ago was willing to offer a premium for a long-term supply contract. And a premium over the in-value price, and that reflected the perceptions then. Now there's still some hangover from the embargo, but it seems to me that what people are legitimately concerned about in the future is, not reliability of supply, but price. That is, as virtually nobody anticipates another embargo for a whole series of reasons, even when the supply gets tight again. By that time all the OPEC countries will have been so co-opted into the world capital system they will such enormous domestic import demand, they will be so integrally tied in with the Western financial system that they just wouldn't....that it's almost out of the question they'd participate in something like that. There are a whole number of reasons why what people are concerned about is if the price turns up again. And, unless you give a fixed price contract.... I don't even know whether you could get somebody to pay a premium for a fixed price contract, because the world oil prices are going down now. And virtually nobody expects them to go up faster than inflation until.... for the next five years, at minimum. The question is - when does it turn up? And that depends on a lot of things that we can't predict.

Now the ALPETCO group is operating on the premise that there are chemical purchasers, particularly in Japan, that will offer a premium for an assured supply of petrochemicals. I think they're a minority of one in that respect. They may be right, but none of the major chemical companies and none of the major oil companies believe. And they're going to have to beat their way into a market which is pretty much tied up by the majors already and in competition with a great number of new petrochemical facilities that are going in in OPEC countries and in third-world countries that want to have them for just the same reasons Alaska does. They want them for diversification of their economies, they want to create jobs, they want it as a symbol of national prestige, and in every case that I've looked at they are willing to subsidize. So they're willing to take a substantial amount of the risk. In Saudi Arabia, Saudi enterprises are taking fifty percent of the thing.

In Korea, which is has no feedstock advantage, the Korean government is undertaking to back-stop them on any operating losses. In Singapore, again, there seems to be....the government seems to be willing to share the risk. In Iran the government is contributing the feedstocks as its equity. And so, then, if there's a ....they are in a position to do so. So we're looking at competition in the world market with a lot of jurisdictions where they're willing to offer something more than Alaska is to beat their way into the market. And there's a large ethylene-producing surplus in the world today. All the projections show that it will be greater in 1980 than it is today. Now that that surplus would be worked off in 1985 if we have normal rates of growth and if no new facilities are planned in other countries between now and then.

So, I don't know whether it pays to.... If these people will take the crude, and if they can get these hell-or-high water contracts, and get the thing financed, this may be the last chance. Now, if they tell you it's the last chance, that means they know they're in a sliding market. If they told you you'd better do it now or you'll never be able to do it again, they would suggest they have the conventional view of the wisdom of the project and that they'd better convince the bankers before the bankers know what's really happening to the market. too. But, as I say, it's....I don't know....

MR. PARR:

Let me ask you.... One of the previous witnesses of the day, I made this statement and the answer was yes. About the time this project should go on-line in 1983 you'll have a seller's market. Now, you just referred to a buyer's market. And the answer was yes. This was another one of the expert witnesses. Do you disagree with that, or are you agreed?

DR. TUSSING:

No, I would say that is the earliest possible....and I suspect it will be much later than that.

MR. PARR:

Well, that's when the facility goes on line?

DR. TUSSING:

Okay. Okay. But the state's not getting any premium for this oil. If it was going to be a buyer's market in 1983, a seller's market in 1983, in which security of supply becomes important, then your conclusion would.... If that's the case, then the state would do better not to sell its oil under terms now that

it gets only the in-value price.

MR. PARR:

That leads to my second point, then. You said that oil prices are going down. I'm not an economist, but I understood that we were using more oil than is being produced - supply and demand should be driving the oil prices up, not this year and I don't say next year, but isn't the long-range thing that involve prices like everything else be going up?

DR. TUSSING:

Well....

MR. PARR:

....and the more that the demand outstrips the supply, the more they'll go up?

DR. TUSSING:

Well, demand is not outstripping supply now.

MR. PARR:

This year, this year.

DR. TUSSING:

This year or next year. So, until the mid-80's, sometime in the mid-80's at the earliest, the pressures on world oil prices will be down. I think there's pretty general agreement that until 1982 or 1983 there are not going to be any increases in the world price of oil above the rate of general inflation.

How long after that it goes you get the C.I.A. saying 1983, and you get the U.N. saying 2,000, and there are other people who say that it's like the horizon - the closer you get to it, it withdraws. Say, if you get out past 1990, not only are the.... there may be large developments of conventional oil but, if these high prices maintain all that time, we end up re-defining petroleum, or changing our definition of petroleum.

There are three deposits of heavy hydro-carbons in the Western Hemisphere that I can name, and there may be others, each of which have more oil in them than all the conventional crude reserves of conventional oil in the world. Any one of them - they're all in the vicinity of a trillion barrels of crude reserves - the (indisc.) tar sands, the Colorado oil shales, the Orinoco (ph) tar belt in Venezuela. Those have not been economic resources in the past because it's always been far cheaper to produce or purchase....

/Whereupon the tape recorder apparently ran out of tape/

I don't see anything the state gains by selling now on a long-term contract at the in-value price, because they are going to get that anyway. In terms of selling, the state is not getting any premium for the long-term sale. The state may get a petrochemical plant. I personally doubt it, but it may get a petrochemical plant. Now, if it wants it, it's got to take some risks. Any enterprise that comes in, whether it uses state royalty oil or anything else, is going to ask to be bailed out if it gets into trouble. If ALPETCO went to SOHIO....incidentally, if SOHIO's oil is cheaper than in-value price, SOHIO's really got a problem. Ask them why they don't try to buy it from SOHIO. Well, because of the political involvement of the state it has a symbolic value, and the state selling its royalty oil may.... SOHIO probably just doesn't believe that the thing's got any potential and won't be involved in it, but they would do better going to.... Suppose they did go to SOHIO and got the oil and got a jump. If they got in trouble they'd still come to the state, whether it's the state royalty oil or not. If they couldn't meet the debt service, they would come to the permanent fund and ask for re-financing. Here this project for, what is it, four-thousand jobs, and they had that last fifteen percent of financing to put together, and they were buying SOHIO's oil, of course they'd come. Or, if you've got a big bottom-fish processing plant, they've evidently got no objections to the state taking some of the risks and providing capital subsidies for bottom fisheries. So, what's so sacred about something that uses the royalty oil? Every business is going to have to be bailed out, and we're going to have the pot full of money to bail them out with. The risks to the state on ALPETCO aren't that much worse than the risks on anything else.

Let me wind up with one thing....with one suggestion to the Committee. One of my terms of reference here was how the Legislature does resolve the actual legal, analytical policy questions presented by the contract. When I was working in U. S. Senate in the Energy Committee, the Interior Committee, we had a procedure for hearings of this sort in which the staff would make up a long series of written interrogatories organized into the factual questions, the statistical background, things like that, legal questions, analytical questions, and things like projection of future trends and how things work, and policy questions. And these could run....sometimes there would be four or five questions, sometimes there would be four or five pages of questions, and the witnesses, governmental witnesses or the industry witnesses, would be sent these over the signature of the Chairman some weeks in advance, or

far enough in advance of the hearing as was practical. At the same time the hearing was scheduled the interrogatories would be published along with the official notice of the hearing. Then the witness would be required to bring a prepared statement responsive to these things and to deliver it to the Committee twenty-four hours before they appeared.... before the witness appeared. So, again, the members of the staff would have a chance to look at it, because a lot of the questions revolved around very difficult legal points or complex statistical and analytical problems that you really can't cope with just off the top of your head, and which the witness can't cope with off the top of his head. At the same time you get the witness on the record as to what he means and it's very difficult for him to back out or change his premise.

Now, this would be particularly useful with this contract where there is some....the question, what does the contract mean. Section 2.3 has the phrase....ALPETCO can exercise its option to purchase as under circumstances which are triggered by a proposal to offer the oil for sale to another purchaser at a lower price. Well, what is proposed to be offered mean? Does that mean the Commissioner has simply asked for proposals? Now, some people say we need a fancy legal expert to do this. You don't need a fancy legal expert to find out what that means. Because, if the thing gets to court, if it's ever going to be litigated, if it gets to court, what does the judge want to know? The judge wants to know what is the intention. What did the contracting parties intend by this? He doesn't go to his legal dictionary and look up propose to be awkward. He goes to the men of the Royalty Board or he takes testimony from the two parties as to what was said in negotiations, and they present whatever they can. And, so, if you ask the question, if you have a series of interrogatories and say, what does this mean - does it mean that such and such? - and you ask both the Administration and ALPETCO to answer it, either they get together on the answer, which is perfectly proper, in which case they give you an answer, and you know what that means. Henceforth, that is what it means. Because if anybody questions it, the other side just goes into court and say before the Joint Committee of State Legislature they say their understanding of it was this. So, that's what it means. If they come up with different answers, and it's a serious thing, you've got to reject the contract because you can't ratify a contract when the two contracting parties don't agree on its meaning.

This list of questions prepared by Legislative Affairs, questions to be answered in these hearings, is exactly the kind of thing you've got in mind. They've got to be sharpened, but there are some very good questions in there that are going to fall between the cracks in this hearing. Or, for instance,

Fred (indisc.) will tell the Chairman the answer to one of them. But he's not on a public record in such a way that you've also asked ALPETCO the same question, or, if it's a question having to do with what's going to happen under what circumstances where you've asked the consultants to respond to the same thing on the record where you can compare their answers. And I would strongly suggest that you get your Committee staff, or Legislative Affairs, to put together a series of questions of this sort which can be directed, above all, to the two sides that are contracting this but, also, to the extent they're appropriate, can be directed to the consultants. And you can ask the consultants, to within their particular competence, to respond to these various questions.

CHAIRMAN MILES:

Are there any questions for Dr. Tussing?

Thank you very much. It was exciting and enlightening.

AGO 559765

SCOMM

#14:18

Joint Gas Pipeline Committee
Alaska State Legislature

SEN. MIKE COLLETTA — CO-CHAIRMAN
SEN. FRANK FERGUSON
SEN. BILL SUMNER
REP. JOE HAYES

REP. BILL MILES — CO-CHAIRMAN
REP. CHAT CHATTERTON
REP. TERRY GARDINER
REP. CHARLES PARR

EX-OFFICIO MEMBERS
MR. ROBERT LERESCHE
MR. JACK BACKMAN

POUCH V
JUNEAU, ALASKA 99811
(907) 465-3779

JOINT GAS PIPELINE COMMITTEE

REPORT

on the status of the contract between the State of Alaska and the Alaska Petrochemical Company, and the progress of the Alpetco project utilizing Alaska royalty crude oil; May 15, 1980

AGO 559766

The Constitution of the State of Alaska calls for the Legislature to provide for the utilization, development and conservation of all natural resources belonging to the State, including land and water, for the maximum benefit of the people. It was within this context that the Legislature ratified the agreement for the sale and purchase of state royalty oil, as amended, to the Alaska Petrochemical Company on June 18, 1978. Since that time there has been little done in the way of legislative oversight of the project and little or no legislative comment on its progress. However, as a critical juncture in the contract is upcoming -- the taking of royalty oil by Alpetco -- the Legislature has exercised its oversight mandate and started reviewing the status of the project and the compliance of Alpetco with the contractual intent and provisions.

At the request of the Speaker of the House, the Committee undertook an extensive review of the Alpetco project and held hearings on April 28 and May 8, 1980. Several issues surfaced during this review process which form the basis of this Committee report:

1. Present and projected future crude oil needs of existing instate refiners indicate crude supply deficits for both current and future operations;

AGO 559767

2. The project, as presented to the Legislature in 1980, differs markedly from the project of 1978, with the people of Alaska receiving substantially reduced material benefits;
3. Substantial doubt exists as to the degree with which Alpetco complied with its contractual obligations, specifically those under Art. 10.2.3, the 18 month benchmarks, and Art. 4.2.1, reasonable diligence;
4. The economic feasibility of the Alpetco project remains undemonstrated, and the recent, sudden withdrawal of Alaska Interstate Company increases doubts as to the project's longterm economic viability; and
5. The State risks not receiving full value, wise development and associated benefits from the in-kind use of royalty oil if Alpetco takes interim royalty crude beginning July 18, 1980.

These issues will be examined in more detail in the following report, with the Committee's findings stated on each.

ISSUE 1: PRESENT AND PROJECT FUTURE CRUDE OIL NEEDS OF EXISTING INSTATE REFINERS INDICATE CRUDE SUPPLY DEFICITS FOR BOTH CURRENT AND FUTURE OPERATIONS

The state's three refiners (Tesoro Alaska Petroleum, Chevron, and Earth Resources), and one prospective regional refiner (Tanana Valley Refining) testified as to their present and projected crude oil needs, and how those supply projections affect their current operations as well as their plans for expansion.

AGO 559768

Tesoro Alaska Petroleum indicated it has a current crude supply deficit of 14,000-15,000 barrels per day. Presently, Tesoro has met this deficit through a series of shortterm exchanges and a six month contract with the State for 4,600 barrels per day of North Slope crude. Tesoro's base supply is 34,000 barrels per day while the capacity of its Kenai refinery is 48,500 barrels per day, of which 15% can be North Slope sour crude. For the Alaska market, Tesoro produces motor gasoline, diesel fuel and commercial aviation fuel; residual fuel is exported. The current shortage of 14,000 barrels/day is expected to become a supply deficit of 31,000 barrels/day by 1981, due to declining production in Cook Inlet.

Chevron Alaska is currently the only instate refiner not receiving any royalty oil. Chevron vice-president R.F. Walsh testified, however, that receipt of royalty oil may be critical to Chevron's continued operation of its Nikiski refinery. On a longterm basis, Chevron estimates a need for 6,000 barrels/day of crude for the Nikiski refinery, plus 25,000 barrels/day for its California refinery to back up continued supply of products from that refinery to Alaska. Chevron operations currently supply about 24,000 barrels/day or 35% of the light products used in Alaska, plus 60% of the state's requirement for asphalt.

Earth Resources Refinery reported a current capacity of 32,000 barrels per day with an expected capacity of 42,000 barrels per day by October. Its crude supply is secure and adequate for its current facility because of its royalty oil contract with the State of Alaska. Earth Resources proposes to expand its refining capacity to 65,000 barrels per day by October of 1982 or 1983 in connection with a proposed petrochemical facility. Another proposal for future use of royalty crude was presented by Tanana Valley Refining which wants to build a small 5,000-10,000 barrel/day refinery at Fairbanks. The facility would produce middle distillates and gasolines.

THE COMMITTEE FINDS the established instate refiners have invested sizable amounts in Alaska; created jobs for Alaska residents; contributed to state and local revenues; and produced, marketed, and distributed products for use by the state's residents and businesses.

FURTHER certain instate refineries have a current shortage of crude oil and future, larger shortages may result from declining Cook Inlet production.

FURTHER it appears that both present and projected crude deficits may curtail currently established refinery operations and will impede proposed expansions of those operations.

ISSUE 2: THE PROJECT, AS PRESENTED TO THE LEGISLATURE IN 1980, DIFFERS MARKEDLY FROM THE PROJECT OF 1978, WITH THE PEOPLE OF ALASKA RECEIVING SUBSTANTIALLY REDUCED MATERIAL BENEFITS

Ownership

In 1978 Alpetco proposed a $2.5 billion petrochemical plant which was to offer benefits to Alaskans in terms of industrial development, construction work and permanent jobs, revenues, and general economic growth, all with little or no risk to the State.

Originally ownership was vested primarily in Alaskan incorporated companies and regional corporations: Alaska Interstate Company, 60%; Barbour Oil Company, 20%; and Alaska Consolidated Shipping, 20%. (Alaska Consolidated Shipping's 20% share was divided among Seatrain Lines of New York, 9.8%; and Aleut Corporation, Bristol Bay Native Corporation, Calista Corporation, Chugach Natives, Inc., Cook Inlet Region, Inc. and Koniag, Inc., 1.7% each). After the entrance of Charter/Alaska for 70% and E.F. Hutton/Alaska for 6.6% in October of 1979, the original members' total share dropped to 23.4%.

On May 8, 1980, Alaska Interstate Company announced its withdrawal, apparently without compensation for equity invested to date, resulting in the following reallocation of ownership: Charter/Alaska, 84.700%; E.F. Hutton/Alaska, 7.987%; Seatrain Lines, 6.600%; and the six regional corporations, .702% total or .117% each.

THE COMMITTEE FINDS that project ownership has shifted so that over 90% is now held by firms not incorporated in Alaska. FURTHER, these firms were not part of the original consortium; consequently, their assets, liabilities, industry skills and reputation, and business acumen were not reviewed by the Legislature prior to the original contract ratification. FURTHER, E.F. Hutton/Alaska is not authorized to do business in Alaska as it has not registered with the Alaska Department of Commerce and Economic Development.

FURTHER, the sudden unexpected withdrawal of Alaska Interstate without prior notification to the State raises questions about the stability of the joint venture. Rapid shifts in project ownership may affect Alpetco's ability to comply with its contractual obligations and to make due progress on the project, thus creating substantial risks to the state.

Products

In 1978 Alpetco officials repeatedly testified that their project, unlike those of other competitors for royalty oil, was a petrochemicals project, not a fuels refinery. Emphasis was on establishment of a worldscale ethylene plant, and production of ethylene, other olefins and aromatics. Alpetco stressed that they had deliberately chosen a petrochemical plant rather than a refinery, as world demand for petrochemicals would increase faster than fuels demand and the comparative benefits to Alaska would be considerably more. In fact,

AGO 559772

fuels production was mentioned by Alpetco officials in 1978 only in the context of providing a minimum of fuels for Alaska's instate needs. The first "whereas" clause of the contract reflects the mutually understood intention regarding products:

> WHEREAS, it is in the mutual best interests of Seller and Buyer that Buyer construct and operate a petrochemical facility in Alaska to process the oil sold hereunder, said facility to have the capacity to process approximately 30,000 barrels per day of crude oil into energy fuels for in-state distribution and sale."

In 1980, in contrast, Alpetco proposes to produce 82.3% fuels, 7.8% naptha, and 9.3% aromatics, a products slate almost exactly the inverse of its 1978 configuration.

THE COMMITTEE FINDS that the Alpetco project is a fuels refinery, not a petrochemical facility. At best, it appears that the phase one facility will produce less than 20 percent chemicals and more than 80 percent fuels.

FURTHER, Alpetco has a sales agreement with its majority partner, Charter/Alaska, for 15 years which is based on the current fuels products slate.

FURTHER, the inclusion of naptha as a petrochemical is open to debate. The Committee notes that Alpetco's own 1980 documents mention naptha not as a petrochemical, but as a feedstock from which to make petrochemicals. In addition, it is not clear from the information presented to date that the aromatics will be produced as separate products rather than sold as a heterogenous material. Without naptha, petrochemical production is less than 10% of the proposed products.

FURTHER, although the Committee recognizes the need to build a facility in stages, the testimony of Alpetco officials indicates no binding commitment to construction of any subsequent stages of the facility. Although the Alpetco project may be "still as much a petrochemical facility as it always was," as Commissioner LeResche testified, the Committee finds that today's project is not the worldscale petrochemical facility it expected to be constructed as a result of the 1978 contract ratification.

Marketability

Alpetco's targeted markets remain the West Coast and Japan, with fuels destined for the West Coast and naptha and aromatics slated for Japan. In addition, Alpetco proposes to market 20,000 to 30,000 barrels per day of fuels in Alaska. To date, though, Alpetco's only sales agreement is with its majority partner, Charter/Alaska, for 70% of the product output for a 15 year period. Signed December 5, 1979, the sales agreement includes a proposed products slate of approximately 80% fuels and 20% chemicals. Although the sales agreement is not yet binding, it would appear to indicate Alpetco's intention to market fuels on a longterm basis.

THE COMMITTEE FINDS that despite Alpetco's earlier claims to strong interest by Japanese trading companies and government leaders, and by major U.S. chemical companies, the sales agreement with its own majority partner, Charter/Alaska, represents its own firm marketing activity.

Jobs and Revenues

In 1978 Alpetco repeatedly stated that Alaska would receive between 1,925 and 2,850 permanent jobs during the project's 20 year operations phase. Alpetco stated that the number of jobs created was a direct result of the project being a petrochemicals facility rather than a simpler refinery. Today, Alpetco officials indicate that the number of definite, permanent jobs is 579. Additional jobs might be created if the project moves beyond phase one.

In 1978 Alpetco stated that its annual taxes would provide a total of $49 million in revenues to the State and the local government. In 1980 the annual revenues to the State and local government appear to be about $22.9 million, less than half that estimated in 1978. In part, the reduction in revenue would appear to be the result of the shift in the proposed size of the project from a $2.5 billion facility to a $1.5-1.7 billion facility.

THE COMMITTEE FINDS that the number of jobs for Alaskans has become one-quarter of that promised in 1978, while tax revenues have dropped to less than half of that promised in 1978. FURTHER, the shift in project ownership from an Alaska incorporated firm to a business incorporated in Florida may further impact the total amount of Alaskan revenues.

ISSUE 3: SUBSTANTIAL DOUBT EXISTS AS TO THE DEGREE WITH WHICH ALPETCO HAS COMPLIED WITH ITS CONTRACTUAL OBLIGATIONS, SPECIFICALLY THOSE UNDER ART. 10.2.3, THE 18 MONTH BENCHMARKS, AND ART. 4.2.1, REASONABLE DILIGENCE

Benchmark 10.2.3(a). Provision (a) calls for Alpetco to expend or commit to expend or cause contractually bound third parties to expend or commit to expend at least ten million dollars in total project costs. By contractual amendment, "commit to expend" means contractually binding agreements, contracts and purchase orders. Alpetco submitted a summary schedule showing project expenditures and contractual commitments for a total of $11,377,229.98. The expenditures were reviewed by Peat, Marwick and Mitchell and approved. In a December 3, 1979, letter to the Department of Natural Resources, however, Peat, Marwick, Mitchell stated, "Because the above procedures were not sufficient to constitute an examination in accordance with generally accepted auditing standards, we do not express an opinion on any of the individual amounts referred to above." Although there appears to be little doubt that the company has complied with benchmark (a), Commissioner LeResche, contract administrator for the State, was unable to state what standards or criteria were used by the accounting firm to review the submittal as it did not use "generally accepted auditing standards."

AGO 559776

THE COMMITTEE FINDS that a more prudent course of action would have been for the Commissioner to require the accounting firm to conduct an examination of Alpetco's expenditures in accordance with generally accepted auditing standards.

Benchmarks 10.2.3 (b) and 10.2.3 (c). Provision (b) requires Alpetco to negotiate sale terms with prospective purchasers of products from the petrochemical facility; delineate product requirements, production ratios and quantities for the range of products to be produced from the petrochemical facility; and draft contracts for the sale of products from the petrochemical facility. Provision (c) requires Alpetco to enter into contracts for the sale of at least 70% of the product output from the petrochemical facility.

To meet provision (b) Alpetco submitted a products slate delineating the range of products, based on process optimization and market analysis. The December products slate was subsequently revised in an April 9, 1980, letter to the Commissioner. Alpetco did not submit draft contracts for the sale of products or material relating to negotiations of sale terms with prospective purchasers, contending that the sales agreement submitted under (c) met the benchmark (b) requirement.

To meet the contractual obligation under (c), Alpetco submitted a 15 year product sales agreement between Alpetco and Charter/Alaska for 70% of the product output, as it is described in the sales agreement. At the time the agreement was executed, Charter/Alaska was a 70% partner in the Alpetco Company.

Commissioner LeResche testified that the purpose of (b) was to determine market design three or four years ahead of the completion of the facility to see what markets would be in terms of products and product ratios, and, secondly, to demonstrate marketability for what Alpetco had decided to produce.

The intent of provision (c) was not only to demonstrate marketability, but, more specifically, to provide guarantees for longterm lenders. In its 1978 testimony and subsequent submissions to the State, Alpetco reiterated the necessity and its intent of selling products on longterm take-or-pay contracts with major chemical companies. Alpetco explained that the product sales agreement was tied to longterm financing in that irrevocable take-or-pay contracts would be used as guarantees for project financing, providing assurance to lenders that monies borrowed to finance the project would be promptly repaid. At a minimum, Alpetco said, the take-or-pay contracts would provide for debt service if for some reason the facility does not produce products for delivery to purchasers.

THE COMMITTEE FINDS that (b) and (c) are distinct. As the attorney for the State wrote[1], "In order to avoid reading (b) as wholly redundant with (c) and (h), it seems likely that

---

1. Memorandum from Fred Boness, Attorney at Law, to Commissioner Robert LeResche, Department of Natural Resources, November 13, 1979, p. 13.

(b) requires Buyer to negotiate with prospective purchasers of products for the 30% of the products not sold in satisfaction of (c) -- assuming, of course, Buyer concludes contracts for only 70% of its products." Therefore, under (b) Alpetco should have submitted draft contracts for the remaining 30% of the products not sold under (c). These draft contracts assume greater importance in view of Alpetco's failure to sell 70% of the products to an unassociated firm.

FURTHER, at this time, Alpetco's plans for marketing the remaining 30% of the products remain unknown. Although Alpetco officials testified that they are in sales negotiations, their monthly progress reports indicate no marketing activity since the signing of the sales agreement with Charter/Alaska.

FURTHER, Alpetco officials testified that during the interim period, each of the partners is responsible for the disposition of its pro-rata share of royalty crude rather than the joint venture assuming that responsibility.

FURTHER, the Committee finds that Alpetco's sales agreement with its own majority partner is not as strong an indication of product marketability as would have been possible through sale to a totally unassociated firm.

FURTHER, the sales agreement is with a company, Charter/Alaska, whose stated capital assets are $1,000 (Certificate of Authority To Transact Business in Alaska, No. 13, issued January 17, 1980, by the Alaska Department of Commerce and Economic Development).

FURTHER, the sales agreement between Alpetco and Charter/Alaska is not a binding, irrevocable document. It is conditional on Charter/Alaska's "final approval of definitive documents relative to long-term loans of funds for the Refinery, the Terminal and related facilities and to the execution by December 18, 1980, of such documents by Alpetco and the lenders providing such funds" (Sales Agreement, p. 13). That is, the sales agreement is not being used as a guarantee for project financing, as was originally contemplated, but is itself dependent on project financing being established.

Benchmark 10.2.3(d). Provision (d) requires Alpetco to obtain or cause contractually bound third parties to obtain written commitments to lend or invest at least $1.5 billion in the project. Alpetco reported this requirement had been met in the following ways:

(1) authorization to issue $600 million in tax exempt industrial revenue bonds by the City of Valdez with the proceeds to be loaned to Alpetco; the bonds are to be underwritten by E.F. Hutton, subject to a number of conditions;

(2) a proposal by Thyssen Theinstahl Technik "to arrange financing" of up to $750 million in consideration for Thyssen, along with Foster Wheeler Energy Corporation, receiving an engineering and construction contract for the project; and

AGO 559780

(3) equity financing by the partners of $350 million, with each partner responsible for a pro-rata share of the funds. Taken as a whole, the intent of provision (d), along with provision (e) for interim financing, is clearly to substantiate the project's creditworthiness and financial feasibility, by documenting the firm commitment of lenders or investors. In evaluating Alpetco's actions regarding benchmark (d), it would appear that the State should concern itself that the commitments are, indeed, firm commitments and that the lenders and the borrower are each serious about the loan. An indication of that seriousness would be that the commitments are binding contracts, not merely expressions of interest.

The Valdez Bond.

A review of the Valdez bonding proposal shows it to be highly conditioned, including a provision that E.F. Hutton will undertake to buy and reoffer the bonds only if the bonds receive an investment grade rating by Standard and Poor's Corporation. Another condition is that E.F. Hutton's obligation is subject to a subsequent agreement by Alpetco to maturity schedules, interest rates and other terms.

Alpetco officials' testimony substantiated that the Thyssen arrangement contains no terms, no drawdown schedule, no interest rate, no security provisions. Considerable discussion during the public hearings centered on the fact that the Thyssen agreement is not to lend or invest, but to arrange financing. The following April 28th exchange between Rep. Joe McKinnon and Mr. Willard Hanzlik, financial advisor to Alpetco, exemplifies the discussion:

> Rep. McKinnon: If last December 18th you had gone to Commissioner LeResche and said the financing we've arranged is $600 million in bonds from the City of Valdez and we've got $350 million in equity and we intend to go out during the next year and arrange an additional 750 million dollars worth of loans, would that have met the benchmark?
>
> Mr. Hanzlik: No.
>
> Rep. McKinnon: And you're contending that by contractually obligating somebody to do what wouldn't have met the benchmark if you yourself had done it, you've met the benchmark.
>
> Mr. Hanzlik: Exactly. Sure.
>
> Rep. McKinnon: I don't see the logic there.

AGO 559783

THE COMMITTEE FINDS that it,too, does not see the logic. A commitment by Thyssen to arrange financing in no way obligates Thyssen to lend or invest in the project. Hence, a substantial cloud exists over whether Alpetco has complied, in fact, with benchmark 10.2.3(d).

FURTHER the Committee finds it difficult to understand how Alpetco finds Thyssen's commitment, such as it is, better than that of other investors in that there are no terms. The lack of specificity of terms also greatly lessens the possibility that a court would find the agreement legally binding on Thyssen.

FURTHER the Committee finds that the Thyssen arrangement fails to meet the intent of provision (d), to demonstrate the project's financial feasibility by December 18, 1979.

The Partners Equity Investment.

As of December 13, 1979, the three partners had agreed to commit $350 million in funds to the project. Charter/Alaska was to commit $245 million; Alaska Petrochemical Company, $81.9 million; and E.F. Hutton/Alaska, $23 million, each based on their pro-rata share of the joint venture. No letters of commitment were included from any of the six regional native corporations. Each company's commitment was subject to the company and the respective parent companies approving the final definitive loan documents and to those documents being executed by December 18, 1980.

At the May 8, 1980, hearing, Commissioner LeResche indicated that Charter/Alaska would assume the obligations of Alaska Interstate after that company's sudden withdrawal from the joint venture. Charter's obligation for equity investment now totals 84.7% or $296.45 million, plus backup for Seatrain's $23.1 million.

THE COMMITTEE FINDS that, in light of the sudden withdrawal of Alaska Interstate, a review of the remaining companies' financial capacity and ability to meet the equity investment commitment would be in order.

FURTHER, under Art. 4.2.1 calling for reasonable diligence, the Commissioner should review the new joint venture agreement to ascertain anew the extent to which the remaining partners and their respective parent companies remain committed to the project and to the equity investment commitment.

Benchmark 10.2.3(e). Provision (e) calls for Alpetco to obtain a commitment or commitments for interim financing for the construction of the petrochemical facility. To meet this requirement, Alpetco submitted letters from two banks, Chemical Bank of New York and Manufacturers Hanover Trust. The two letters were subject to a number of conditions, including a review of the economic projections and underlying assumptions which demonstrate the viability of the project.

AGO 559785

Alpetco also indicated that it might provide for interim financing through use of an early issue of the tax exempt Valdez bonds. It further indicated the partners might determine to contribute the total equity required during the early months of construction, thus eliminating the need for interim construction financing. It subsequently also obtained a letter from Thyssen committing Thyssen "to arrange interim financing" for up to $150 million if the banks do not provide the funds.

THE COMMITTEE FINDS that the commitments for interim financing provided by the banks to be expressions of interest, not contractually binding agreements. As submitted, the banks' letters do not offer any protection to the State as far as actual performance goes.

FURTHER the Committee finds that the backup commitments for interim financing to be provided by Thyssen or by an early issue of the Valdez bonds or by the partners are of the caliber and quality of their comparative commitments for longterm financing under provision (d).

FURTHER the Committee finds that the materials submitted by Alpetco for compliance with provision (e) do not meet the intent of the benchmark -- to demonstrate lenders and investors confidence in the project's economic feasibility.

AGO 559786

Benchmark 10.2.3 (f). Provision (f) requires Alpetco to complete and file an Environmental Impact Assessment on the petrochemical facility. A draft Environmental Impact Statement was published December 7, 1979, and a final EIS published April 25, 1980.

THE COMMITTEE FINDS that Alpetco has complied fully with provision (f).

FURTHER the Committee finds that, according to testimony offered by staff and administration officials, Alpetco's EIS is exemplary.

Benchmark 10.2.3 (g). Provision (g) requires Alpetco to complete and file all material state, local and federal permit applications.

THE COMMITTEE FINDS that Alpetco has complied fully with provision (g).

FURTHER the Committee finds that, according to testimony offered by staff and administration officials, that Alpetco's permitting procedures have been exemplary.

Benchmark 10.2.3 (h). Provision (h) states that Alpetco must "complete plant design and optimization necessary to obtain a definitive project cost estimate ("definitive" meaning a cost estimate containing no more than fifteen percent (15%) variance in anticipated costs)."

AGO 559787

To indicate its compliance with this benchmark, Alpetco submitted a general summary of work done on plant design and process optimization, and detailed engineering studies by UOP Process Division, C-E Lummus Company, R.M. Parsons Company, Heat Research Corporation and Exxon Research and Engineering Company. The Department of Natural Resources employed Pace Company to review the documents, and Pace reported that the overall process configuration for the facility had been determined. The optimization work and the process engineering are sufficient, Pace indicated, for a cost estimate to be prepared with a variance of 15 percent or less. At the two public hearings, the Committee received conflicting, or at least confusing testimony about (h). Alpetco officials testified that they did not submit a definitive cost estimate to Commissioner LeResche, while Commissioner LeResche testified that they did. Both Alpetco officials and Commissioner LeResche testified that such a definitive cost estimate was, in any case, irrelevant.

THE COMMITTEE FINDS that the lack of a definitive cost estimate is far from irrelevant. At best, the difference in opinion about the relevancy of a definitive cost estimate indicates a substantial ambiguity in contractual language.

FURTHER the Committee finds that clearly Alpetco no longer plans to construct the $2.5 billion project originally described in 1978, a change which adversely impacts the amount of state and local revenues the project will generate.

AGO 559788

FURTHER the Committee finds that the Commissioner's approval of the benchmark without administrative review of the definitive cost estimate substantially reduces the validity of the benchmark as a check on contractual progress. Alpetco is contractually obligated to spend a total of $1.5 billion by the 72th month; the longterm financing for the $1.5 billion has to be in place by December 18, 1980. It is the understanding of the Committee that longterm commitments by major investors often depend on adequate preparation of engineering design and cost estimates. Yet Alpetco officials testified that, at this time, they do not have cost estimates in hand with which they would approach prospective lenders.

ISSUE 4: THE ECONOMIC FEASIBILITY OF THE ALPETCO PROJECT REMAINS UNDEMONSTRATED, AND THE RECENT, SUDDEN WITHDRAWAL OF ALASKA INTERSTATE COMPANY INCREASES DOUBTS AS TO THE PROJECT'S LONGTERM ECONOMIC VIABILITY

Much of the material presented under the discussion of Issue 2 (Alpetco's compliance with contractual obligations) is pertinent to a discussion of the project's economic viability. Indicators of the project's inability to demonstrate adequate financial feasibility and to find solid favor with potential investors and backers include the following:

·the withdrawal of Alaska Interstate with no apparent compensation for an equity investment of about $5 million dollars;

·the venture's inability to establish firm markets with anyone other than its own majority partner;

AGO 559789

·Alpetco's inability to execute longterm take-or-pay contracts to use as guarantees for project financing;

·the substantial doubt as to the extent and firmness of commitments to lend or invest at least $1.5 billion in the project;and

·the similar state of interim financing commitments.

ISSUE 5: THE STATE RISKS NOT RECEIVING FULL VALUE, WISE DEVELOPMENT AND ASSOCIATED BENEFITS FROM THE IN-KIND USE OF ROYALTY OIL IF ALPETCO TAKES INTERIM ROYALTY CRUDE BEGINNING JULY 18, 1980

In 1978 Alpetco pledged that its contract would present little or no risks to the State of Alaska. In a more cautious vein, Commissioner LeResche testified on March 14, 1978, "There are risks inherent. I submit that these risks are very minimal compared to the extreme benefits that are possible under this contract." Among the risks LeResche outlined were added administrative burdens for the State, litigation of the storage question, and loss of the option to do other things with royalty oil in the period between the approval of the contract and the following 18 months. He also discussed future risks possible under Arts. 2.3 and 2.4, the option terms.

The 1980 testimony and record, however, raise several areas which deserve examination in terms of the potential risks the State now faces. In particular, Alpetco's desire to take Alaska royalty crude on an interim basis, beginning July 18, 1980, prior to facility construction and operation raises questions.

On a practical level, the lifting of 150,000 barrels per day of oil from the Valdez terminal requires Alpetco to make arrangements for the actual physical transfer of the oil. On April 28, 1980, Alpetco general manager Dudley Parker testified, "We have not made tanker arrangements, to be honest with you." Nor had Alpetco made firm arrangements to exchange or otherwise sell or dispose of the oil at that time. They also indicated that each partner in the joint venture is making separate arrangements for the disposal of its pro rata share of interim crude. On May 8, 1980, Commissioner LeResche testified that he had no information as to how E.F. Hutton/Alaska, Seatrain or the six native regional corporations plan to dispose of their respective shares.

In order to qualify for early taking of royalty crude, Alpetco must have "actually expended at least $100 million in Total Project Costs," not including the price of the royalty oil itself. As of April 30, according to Alpetco's statements to Commissioner LeResche, they had spent a total of $16,813,731. The Commissioner had not received a final list of how Alpetco plans to spend the remaining $83 million, although Alpetco indicated that the list would be submitted by mid-May. Alpetco testified on April 28 that they will expend the $100 million by June 30.

AGO 559791

As of May 8, the Commissioner had not defined how he would evaluate "an actual expenditure" nor the timeline for evaluating Alpetco's compliance with the requirement to actually expend the funds prior to receipt of royalty crude. He stated, "The fact is, the problem with that coming in as an amendment with no timeframe is that they could on June 18 not have made a hundred million dollar expenditure but make it by July 18 and still arguably have a call on the oil because all that had to do was precede by one microsecond their taking the oil...."

Discussion at the May 8th hearing also substantiated that the case between the State and North Slope oil producers over royalty cleaning costs is still unresolved ("Amerada Hess v. State of Alaska"), and that the April 9, 1979, memorandum of decision and order by Judge Allen T. Compton has not yet been entered as a final order.

THE COMMITTEE FINDS that Alpetco has failed to make firm arrangements for royalty oil transfer and transport less than forty days from the required date of notification for tendering space on the Trans-Alaska pipeline and less than eighty days from the actual transfer of oil.

FURTHER, the Administration lacks any information as to the plans of the minority partners of the joint venture for disposition of their shares of the royalty oil.

AGO 559792

FURTHER the Committee recognizes that the State has provided a backup in the event of Alpetco's failure to take crude oil as scheduled. The backup is in the form of the current royalty oil contract between the State and Tesoro Petroleum which calls for Tesoro to take delivery of royalty crude July 18, if Alpetco should not, and to continue receipt for a period of time up to December 31, 1980.

FURTHER, the Committee finds that delivery of royalty oil to Alpetco for export from the State from July 18, 1980, through 1983 precludes the use of the oil for established instate refiners with current crude supply deficits.

FURTHER, the Committee finds that lack of an established administrative timeline for evaluation of Alpetco's compliance with the $100 million expenditure requirement may lead to a situation where Alpetco can receive royalty crude prior to the Administration's verification of the Company's compliance with its contractual obligation.

FURTHER, the Committee finds that the lack of resolution of the current litigation between the State and North Slope producers over royalty oil leaves open the question of whether the State will receive at least the equivalent of the invalue price for royalty oil taken in kind.

AGO 559793

FURTHER, the Committee finds some indications that once Alpetco receives royalty oil, it has a continued claim on that oil for a period of time, even in the event that it does not complete and operate a petrochemical facility. Under this circumstance, Commissioner LeResche testified, Alpetco would pay the State the going price for the oil. The Commissioner's assessment, however, ignores the fact that the State expects to receive more for its royalty oil taken in kind than simply its monetary value. Continued export of royalty oil forecloses instate options for instate refining, processing, marketing and distribution of products.

FURTHER, the Committee finds that allowing Alpetco to take delivery of royalty crude on July 18, 1980, legitimizes Alpetco's claim to the oil, despite the substantial doubts that exist as to Alpetco's compliance with its contractual obligations. Hence, early delivery of royalty crude to Alpetco is unacceptable.

FURTHER, the Committee finds that the Commissioner has chosen to administer the contract in a negligent and imprudent manner, increasing the risks to the State that Alpetco will not fulfill properly its contractual obligations. The Committee finds this level of administrative watchfulness unacceptable and, accordingly, will continue to exercise an ongoing role of close legislative oversight.

AGO 559794

Submitted as a public report this 15th day of May, 1980.

Bill Miles
Co-Chairman

Mike Colletta
Co-Chairman

AGO 559795

HOUSE RESEARCH AGENCY
Pouch Y - State Capitol
Juneau, Alaska 99811
4653991

MEMORANDUM

February 20, 1980

TO: Representative Bill Miles

FROM: Susan Brody, Issues Analyst SB

RE: Alpetco Contract Compliance, 18 Month Benchmark Request #31

INTRODUCTION

This memorandum is in response to your request for an evaluation of compliance with the Royalty Oil Contract, specifically the 18 month benchmark provisions of Article 10.2 (3). These provisions are listed below.

(a) Expend or commit to expend or cause contractually bound third parties to expend or commit to expend at least $10 million in total project costs.

(b) Negotiate sale terms with prospective purchasers of products from the petrochemical facility; delineate product requirements, production ratios and quantities for the range of products to be produced from the petrochemical facility; and draft contracts for the sale of products from the petrochemical facility.

(c) Enter into contracts for the sale of at least 70 percent of the product output from the petrochemical facility.

(d) Obtain or cause contractually bound third parties to obtain written commitments to lend or invest at least $1.5 billion in the aggregate for payment of total project costs.

(e) Obtain a commitment or commitments for interim financing for the construction of the petrochemical facility.

(f) Complete and file an Environmental Impact Assessment on the petrochemical facility.

(g) Complete and file all material state, local and federal permit applications.

AGO 559796

(h) Complete plant design and optimization necessary to obtain a definitive project cost estimate ("definitive" meaning a cost estimate containing no more than 15 percent variance in anticipated costs).

According to the contract, these requirements are to be met within 18 months after the effective date, or by December 18, 1979. It is important to note, however, that the contract allows the Commissioner of Natural Resources to extend the 18 month benchmark period by 6 months. Therefore, the contract does give the State the option of requesting further clarification or documentation on any of the contract items, (a) through (h), before making the final determination that Alaska Petrochemical Company has complied with Article 10.2 (3).

Alaska Petrochemical Company submitted evidence of contract compliance to the State on the following dates: November 19, December 5, 13, and 17, 1979. Following a December 5 meeting in Juneau between the Alaska Petrochemical Company, Commissioner Bob LeResche and Attorney Fred Boness, the State requested further documentation on several contract items. Alaska Petrochemical Company submitted revised documents on December 13 at which time a second meeting was held in Seattle. This last meeting resulted in one final request by the Department of Natural Resources for clarification of the information submitted and Alaska Petrochemical Company transmitted this additional documentation to the State on December 17.

Responsibility for evaluating the Article 10.2 (3) contract items was shared within the Department of Natural Resources by the Division of Minerals and Energy Management (DMEM) and the Commissioner's office. DMEM was responsible for evaluating Alaska Petrochemical Company's compliance with items (a), (b), (g), and (h). They hired two consulting firms to assist them in this effort: the Pace Company and Peat, Marwick, and Mitchell. The Commissioner's Office evaluated items (c), (d) and (e) with assistance from Attorney Fred Boness and Peter Lewis, financial consultant.

Tom Cook, Director of DMEM, transmitted his Division's finding in writing to Commissioner LeResche by memorandum on December 18, 1979. However, as far as we can determine, no written findings were prepared by the Commissioner's office evaluating Alaska Petrochemical Company's compliance with contract items (c), (d) and (e). According to Kay Brown, Special Assistant to the Commissioner, both Fred Boness and Peter Lewis were recently requested by LeResche to prepare written findings on the contract items they reviewed and these should be available through the Commissioner's office in about 2 weeks.

In our review of the documents submitted to the State by Alaska Petrochemical Company, we have identified a number of areas where contract compliance could legitimately be questioned. However, the extent to which evidence submitted by the Company is interpreted as satisfying the terms of the contract depends, in part, on the evaluator's perspective. For this reason, we felt it would be valuable to familiarize ourselves with the original concerns of the legislature in regard to the Royalty Oil Contract and to determine what purposes certain contract provisions were intended to serve. Our review of previous documents included the March 1978 transcripts of hearings before the House Royalty Oil and Gas Committee and the final Committee report of April 28, 1978.

It is interesting to note that the House Committee anticipated possible problems with contract compliance and enforcement. The April '78 Committee Report notes:

> In the short-term, it is unlikely the State will be inclined to enforce the letter of the performance benchmarks set out in the contract. Assuming Alaska Petrochemical Company will demonstrate substantial commitment and sincere effort, it may not be realistic to expect that the State will cut Alaska Petrochemical Company off if it falls short of the desired goals.

One of the key concerns of the Committee was a provision in the contract which determines when the Alaska Petrochemical Company may begin receiving oil from the State. Article 2.2 provides that after the Buyer has "obtained the financing commitment referred to in Article 10.2 (3) (d) and has furnished satisfactory evidence of same to Seller, Buyer shall have the right ... to call for the initiation of delivery of crude oil under this agreement." Thus the 18 month benchmark provisions of the contract, especially item (d) are extremely critical because they determine whether Alaska Petrochemical Company will be allowed to receive the State's royalty oil prior to construction of the petrochemical facility.

The Committee was also concerned that sufficent markets might not exist for the products of the proposed petrochemical facility. Specifically, the Committee found that "there is little potential for product purchase in Japan; there is more of a potential on the West Coast and other lower 48 markets, but Mexican petrochemicals may preclude such prospects." Items 10.2 (3) (b) and (c) of the contract address the need for Alaska Petrochemical Company to provide evidence of product marketability. Subpart (b) requires the Alaska Petrochemical Company to "negotiate sales terms with prospective purchasers of products" and to "draft contracts for the sale of the products"; subpart (c) requires Alaska Petrochemical Company to "enter into contracts for the sale of at least 70 percent of the product output."

Another issue in the Committee hearings was an absence in the contract of any firm requirements for in-State processing of the oil. In an attempt to reassure the House Committee on this point, Eddie Rogers, the chief contract negotiator for Alaska Petrochemical Company testified that by meeting the benchmark criteria of Article 10.2, the Company would be demonstrating its intent to process in-State and to process the full 150,000 bpd. Again, this demonstrates the importance of the benchmark requirements of Article 10. They are the primary mechanism for insuring that risks to the State are minimized.

CONTRACT REQUIREMENTS

(a) Expend or Commit to Expend or Cause Contractually Bound Third Parties to Expend at Least $10 Million in Total Project Costs

On December 5, 1979, Alaska Petrochemical Company submitted a summary schedule showing total project cost expenditures of $10,632,217 and contractual commitments of $745,012 for a total of $11,377,229.

The Division of Minerals and Energy Management contracted with Peat, Marwick, Mitchell and Company, certified public accountants, to audit the Company's records to assure that the requirement had been met. In a letter dated December 3, 1979, Peat, Marwick, Mitchell reported that "in connection with the procedures referred to above, no matters came to our attention that caused us to believe that the total project costs reported by the Company should be adjusted."

This review of the Alaska Petrochemical Company's accounts by a reputable accounting firm appears to us as adequate evidence of compliance with Article 10.2 (3)(a).

(b) Negotiate Sale Terms With Prospective Purchasers of Product Requirements, Production Ratios and Quantitites for the Range of Products to be Produced from the Petrochemical Facility; and Draft Contracts for the Sale of Products from the Petrochemical Facility

On December 5, 1979, Alaska Petrochemical Company submitted a schedule identifying the range of product output for Stage I of project development, including the projected 1985 demand for the products and the percent of the total demand that the Company anticipates that it will supply. Less detailed information on products to be produced was submitted for Stages II and III of project development.

The Division of Minerals and Energy Management contracted with the Pace Company of Houston, Texas to evaluate Alpetco's submittal on this part of Article 10.2 (3)(b). In a letter dated December 12, 1979, the Pace Company noted that, "We have reviewed the data submitted by Alpetco to the State of Alaska describing the range of output for the product slate, and the data appear to be consistent with the processing configuration chosen for the refinery."

In light of the Pace Company's findings, we believe that this requirement of (b) has been substantially satisfied. However, in regard to the other two requirements of contract provision 10.2 (3)(b), the Alaska Petrochemical Company did not submit evidence of "negotiated sales terms" or "draft contracts." Instead, the Company referred to its executed product sales contract with Charter Oil (Alaska), Inc. as evidence of compliance with the provisions of (b). The sales contract with Charter Oil (Alaska), Inc. was submitted in fulfillment of 10.2 (3)(c) and is discussed in the following section.

(c) Enter into Contracts for the Sale of At Least 70 Percent of the Product Output from the Petrochemical Facility

To satisfy this benchmark requirement and the requirements of Article 10.2 (3)(b), Alaska Petrochemical Company submitted a product sales contract between the Alpetco Company* and Charter Oil (Alaska), Inc. for 70 percent of the products from the facility. The Alpetco Company is a joint venture of three entities: the Alaska Petrochemical Company (23.4 percent interest), Charter Oil (Alaska),Inc. (70 percent interest), and E. F. Hutton (Alaska), Inc. (6.6 percent). In other words, a 70 percent partner in the petrochemical facility project has agreed to purchase 70 percent of the products from that facility.

The product sales contract appears to satisfy the letter of 10.2 (3)(c). It is a valid and meaningful contract that guarantees that the Alpetco Company will receive payment for 70 percent of its products. While it may not be an "arms length" contract, it is a contract between two distinct entities. On the other hand, the product sales contract does little to demonstrate the actual marketability of the products of the petrochemical facility. Charter Oil (Alaska), Inc. will still need to identify viable markets for the products it has agreed to purchase from the Alpetco Company.

---

* Alaska Petrochemical Company has requested that their royalty oil contract with the State be assigned to the Alpetco Company, a joint venture formed October 1, 1979. To the best of our knowledge, Commissioner LeResche has approved the assignment.

As noted earlier, the product sales contract was also submitted as evidence of compliance with the terms of 10.2 (3)(b); that is, as satisfying the requirement to "negotiate sales terms with prospective purchasers" and to "draft contracts for the sale of products." However, if both the requirements of (b) and (c) were included in the Royalty Oil contract, it seems reasonable to assume that the parties to the contract contemplated (b) and (c) as independent conditions. It may be helpful to consider the probable purpose of the (b) requirements in determining whether the spirit as well as the letter of the contract has been met. That purpose was probably to insure that progress was being made toward sale of 100 percent of the products and to provide some evidence of the market viability of the project. This purpose does not appear to have been met by the contract between the Alpetco Company and Charter Oil (Alaska), Inc.

The only additional documents submitted by the Alaska Petrochemical Company to demonstrate interest in the products of the facility were letters from four chemical companies: Dow Chemical, USS Chemical, Mitsui, and Mitsubishi. These letters contain expressions of general interest in the products, but do not represent evidence of negotiated sales terms or draft contracts.

Our preliminary conclusions regarding contract terms 10.2 (3) (b) and (c) are as follows:

* It is questionable whether the product sales contract between the Alpetco Company and Charter Oil (Alaska), Inc. fully satisfies the letter of requirement (b).

* It appears that the product sales contract does satisfy the letter of requirement (c).

* The product sales contract falls short of satisfying the spirit of both (b) and (c).

(d) <u>Obtain or Cause Contractually Bound Third Parties to Obtain Written Commitments to Lend or Invest At Least $1.5 Billion in the Aggregate for Payment of Total Project Costs</u>

The Alaska Petrochemical Company submitted evidence of three separate financing arrangements to demonstrate compliance with this benchmark requirement. These include:

* Thyssen Rheinstahl Technik GMBH	$750 million
* City of Valdez	$600 million
* The Alpetco Company Partners	$350 million

The evidence submitted for each party is summarized on the following pages.

Thyssen

On December 7, 1979, Thyssen Rheinstahl Technik GMBH, a West German firm, wrote a letter to the Alpetco Company stating the following:

> We hereby commit to arrange financing of up to $750 million ...to cover cost for the engineering, equipment, materials, construction and other services required for the project. (emphasis added)

K W Thyssen and Foster Wheeler Energy Corporation (a joint venture) is currently under contract to the Alpetco Company to provide engineering services for the petrochemical facility, including an agreement to propose a fixed price for construction by September 1, 1980.

The commitment to arrange financing for the project is subject to the following conditions: 1) that the Alpetco Company acquires or contributes the other $750 million; 2) that the Alpetco Company obtain all necessary permits and approvals and begin taking crude no later than July 18, 1980; 3) that definitive documents relating to long term financing for the project be executed by December 18, 1980 (the 30 month benchmark requirement). Thyssen also provided a "character reference" from the Deutche Bank and on December 21, 1979, sent a supplemental letter to Commissioner LeResche giving examples of three other projects for which it had arranged financing in amounts of over $100 million. In this same letter, Thyssen emphasized that their commitment to the Alpetco project is more substantial than is customarily given on comparable projects at this stage.

The Thyssen letter appears to be an enforceable commitment to "arrange financing" for the petrochemical project. However, Article 10.2 (3)(d) requires the Alaska Petrochemical Company (or contractually bound third parties) to obtain "written commitments to lend or invest." It appears to us that one could legitimately argue that the commitment to arrange financing is not a commitment to lend or invest.

Valdez

On November 19, 1979, the City of Valdez passed an ordinance authorizing issuance of tax exempt industrial revenue bonds to finance the petrochemical facility. A resolution authorizing the mayor to execute a commitment to lend $600 million to the Alpetco Company from the sale of these bonds was passed the same day. The mayor subsequently transmitted a letter of commitment to the Alpetco Company to loan up to $600 million or more. In addition, E. F. Hutton and Co., Inc. wrote a letter to the Mayor of Valdez on November 19, 1979, confirming their commitment to purchase the Valdez bonds subject to a number of conditions.

Several questions about the validity of the Valdez commitment have been raised by Joe La Rocca and others. The two primary concerns are whether the bonds can legally be issued with a tax exempt status and whether the Valdez bond issue and commitment violate AS 37.10.085 (prohibiting the loan of municipal credit to a private corporation).

According to Attorney Fred Boness, a prominent Seattle bond counsel has answered the tax exempt question favorably citing Article 103 (b) (4) of the IRS tax code. That section of the tax code specifically allows tax exempt bond issues for the financing of airports, docks, wharves, sewage or solid waste disposal facilities, air or water pollution control facilities, and several other purposes. The City of Valdez resolution authorizing the commitment of funds to the petrochemical facility clearly states that those funds are to be used for the purposes specified in the IRS Code.

The question as to whether the Valdez commitment violates AS 37.10.085 appears to be easily answered. A 1970 State Supreme Court opinion (Wright v. City of Palmer, 468 p 2d 364) and two legal opinions submitted by the Alpetco Company all support the view that the Valdez bond arrangement is valid under Alaska statutes.

Alpetco Company Partners

On December 13, 1979, the three partners in the Alpetco Company wrote letters committing the following amounts of equity to the project.

Charter Oil (Alaska), Inc.	$245 million
Alaska Petrochemical Company	$81.9 million
E. F. Hutton (Alaska), Inc.	$23.1 million

The above amounts are available on 30 day notice subject to final approval of definitive documents for long term financing of the project by December 18, 1980.

Overall, the terms of Article 10.2 (3)(d) appear to have been partially met. Approximately one-half of the required $1.5 billion in project financing has been committed by the City of Valdez and the Alpetco Company partners in a manner that appears to be valid and binding. However, Thyssen's commitment for the other $750 million in financing is not a true commitment to lend or invest as required by the language of the contract and we, therefore, question whether Article 10.2 (3)(d) has been fully satisfied.

(e) Obtain a Commitment or Commitments for Interim Financing of the Petrochemical Facility

According to the projections of Alaska Petrochemical Company, $92.5 million will be required for interim construction financing. To substantiate its fulfillment of this benchmark requirement, Alaska Petrochemical Company submitted evidence of a number of possible options for interim financing. These include letters of commitment from two banks, an agreement from the City of Valdez to cover some of the interim financing needs through the sale of tax exempt bonds and a commitment to arrange interim financing from Thyssen Rheinstahl Technik.

In its submittal to Commissioner LeResche on December 13, 1979, Alaska Petrochemical Company indicated that although they have provided for interim financing if needed, "it is possible that the partners will determine to contribute the total equity required during the early months of construction, thus eliminating the need for interim construction financing."

Alaska Petrochemical Company submitted letters from two banks as evidence of commitments for interim financing. The letters came from Chemical Bank of New York and Manufacturers Hanover Trust Company, each offering a maximum of $75 million to finance the non-tax exempt costs of construction. Both banks' commitments for interim financing are subject to the following eight conditions.

1. Review of the economic projections and underlying assumptions which demonstrate the viability of the project.

2. Availability of guarantees and undertakings to assure completion of the project and coverage of any cost overruns.

3. Continuance of the Royalty Oil Contract and assurance that petroleum reserves available to Alaska Petrochemical Company are adequate to support all project financing.

4. The final contract of the Alpetco Company joint venture agreement.

5. Availability of sufficient equity to complete the project through the sale of royalty crude oil or otherwise.

6. Sufficient collateral and undertakings to assure repayment of the construction loans.

7. Availability from responsible lenders or permanent financing sufficient to provide a complete "take out" for the interim financing.

8. Commitment from the other bank to provide a similar amount of financing.

The agreements to provide interim financing are also subject to "any other matters that may become relevant from a banking point of view and, by December 18, 1980, our entering into with you a definitive credit agreement containing such terms...as may be relevant in the circumstances."

In light of the many specific and general conditions, neither bank letter would satisfy a strict interpretation of the meaning of Article 10.2 (3)(e). However, the proposal to use proceeds from the Valdez tax exempt revenue bonds for interim financing appears sound, especially if these funds are used for construction of the tax exempt costs outlined in the IRS regulations (103(b)(4)). Finally, the offer by Thyssen Rheinstahl Technik for interim financing is again a commitment to arrange interim financing rather than a commitment for interim financing and thus does not represent an entirely satisfactory fulfillment of the contract requirements.

(f) Complete and File an Environmental Impact Assessment on the Petrochemical Facility

The environmental impact assessment was officially filed with DNR on November 19, 1979. Glenn Akins of the Department of Environmental Conservation acted as State coordinator for the EIS work and a number of other State agencies were involved throughout the preparation of the assessment.

(g) Complete and File All State, Local and Federal Permit Applications

On November 19, 1979, the Alaska Petrochemical Company furnished the Division of Minerals and Energy Management with a list of names and telephone numbers for all government agencies that were required to receive a permit and copies of all permit applications filed. The Division contacted the agencies by phone and confirmed that all had been filed.

(h) Complete Plant Design and Optimization Necessary to Obtain a Definitive Project Cost Estimate (Meaning a Cost Estimate Containing No More Than 15 Percent Variance in Anticipated Costs)

In support of compliance with this benchmark, the Alaska Petrochemical Company submitted a letter describing in general the work completed on plant design and eleven volumes of engineering design, optimization studies and reports prepared by the Company's engineers and consultants.

The State Division of Minerals and Energy Management contracted with the Pace Company of Houston, Texas, to analyze the evidence submitted. In their December 12 letter to DMEM, the Pace Company noted:

> As a result of these optimization studies, the overall process configuration for the refinery and petrochemical complex has been determined. The optimization work and the process engineering performed by various licensors and engineering firms for the project are sufficient for a cost estimate to be prepared with a variance of 15 percent or less.

In light of the Pace Company analysis, it appears to us that the terms of Article 10.2(3)(h) have been met. We do not have the expertise to perform an independent evaluation of the engineering studies and other data submitted in support of this benchmark requirement.

CONCLUSIONS

Our review of the evidence submitted by the Alaska Petrochemical Company indicates that contract items (a), (f), (g) and (h) of Article 10.2(3) have been fully met. However, it appears that terms of contract items (b), (c), (d) and (e) may have been satisified only in part.

To meet the requirements of (b) and (c), Alaska Petrochemical Company submitted a sales contract between the Alpetco Company and Charter Oil (Alaska) Inc. for 70 percent of the products from the petrochemical facility. Although this appears to satisfy the letter of (c) and, to a lesser extent, of (b), we question whether this provides adequate evidence of product marketability.

Article 10.2(3) (d) which requires commitments for at least $1.5 billion in project financing is the most critical of the benchmark provisions. The terms of (d) have been partially met by the commitments of the City of Valdez and the Alpetco Company partners, but the Thyssen Rheinstahl Technik commitment for $750 million in financing may not be a true commitment to lend or invest as required by the language of the contract.

Finally, Article 10.2(3)(e) requires commitments for interim financing. The Alaska Petrochemical Company offered several alternatives for accomplishing this benchmark. However, the letters from the Chemical Bank of New York and Manufacturers Hanover Trust Company are subject to so many conditions that, in effect, they do not appear to provide a substantial guarantee of interim financing.

SB/dp

cc: Representative Malone

ALASKA STATE LEGISLATURE - HOUSE OF REPRESENTATIVES

REPRESENTATIVE JOE McKINNON
POUCH V, JUNEAU, ALASKA 99811

April 28, 1980

M E M O R A N D U M

TO: Joe McKinnon

FROM: James Grandjean JG

RE: Alpetco Contract

The question addressed in this memorandum is whether or not Alpetco has complied with Section 10.2(3)(d) of its contract with the State. This provision provides, in substance, that the contract is terminated unless, within 18 months of the effective date (i.e., by December 18, 1979) Alpetco shall

> "[o]btain or cause contractually bound third parties to obtain written commitments to lend or invest at least One Billion Five Hundred Million ($1,500,000,000.00) in the aggregate for payment of Total Project Cost."

Alpetco proposes to meet this provision through (a) the issuance of $600 million in tax exempt revenue bonds by the City of Valdez to be loaned to Alpetco; (b) a purported commitment by Thyssen to "arrange for" $750 million in additional financing; and (c) $350 million in direct financing by the member companies of the Alpetco consortium. Since the commitments by the Alpetco members are conditioned upon the other financing, the focus of this memorandum is on items (a) and (b) above.

In my view, a defensable argument that Alpetco's performance complies with Paragraph 10.2(3)(d) cannot be made. The manifest purpose and effect of subsection (d) is that Alpetco must, to retain its rights under the contract, obtain commitments from lenders or investors by December 18, 1979 that demonstrate the financial feasibility of the project. It can meet its obligations in one of two ways: through a commitment directly from the lender or investor to lend or invest the requisite amount, or through a commitment made to a "contractually bound" finder on behalf of Alpetco by the lender or investor.

AGO 559807

The Bonding Proposal. The $600 million bond issue to be made by the City of Valdez is to be underwritten by E.F. Hutton & Company. Obviously, until the bonds are in fact offered for sale and purchased, or commitments to purchase them have been made, there are no "commitments to lend or invest" within any possible interpretation of Subsection (d). Although the arrangement contemplates a purchase by E.F. Hutton of the bond issue, and a subsequent reoffering by Hutton of the bonds to the public, Hutton's committment to purchase the bonds likewise does not suffice to comply with Subsection (d).

The terms of the undertaking by Hutton are set out in its letter of November 19, 1979 to Mayor Walker. Condition five to Hutton's undertaking is that the bonds receive a Standard & Poor's "investment grade rating". An investment grade rating will be issued by Standard & Poor's only in the event that it determines that the prospective revenues from the project will be sufficient to repay the bond holders, and Hutton's commitment is therefore, in effect, that it will purchase the bonds only if there is a public market for the bonds, which has not yet been determined.

Accordingly, the situation is no different, in substance, than if Alpetco were now proposing to float the bonds itself it an attempt to raise the necessary revenue, since the terms of the bonds provide that they will be paid for only out of the revenues of the project. Thus, there is no "commitment" on the part of Hutton to purchase the bonds and, in reality, Alpetco has produced nothing more than an offer to attempt to sell bonds.

Condition seven of Hutton's undertaking provides that its obligation is subject to an agreement by Alpetco to "maturity schedules, interest rates and other terms which are commercially reasonable given all the facts and circumstances prevailing at the time the Bonds are available for reoffering." [Emphasis added]. In other words, any obligation on Hutton's part to purchase the bonds would arise only at the time that Hutton attempted to reoffer them to the public, and only to the extent that Alpetco agrees to terms that are satisfactory to Hutton at that time, given the financial soundness of the project. Not only does this condition impose a conceptually impossible term, i.e., that the purchase price of the bonds is to be determined after their purchase, but it effectively permits Hutton to opt out of the entire arrangement by permitting it to impose onerous and impossible terms upon their purchase in the event that the project appears to be a high risk one. Thus, Hutton's "commitment" at this time can hardly be regarded as evidence of the project's financial feasibility or an assurance that Alpetco has the necessary financing to carry it through.

Finally, the second paragraph of Hutton's "committment" letter provides that the price of the bonds to be paid by Hutton to the city of Valdez, and the price at which they

will be reoffered to the public, as well as other essential terms such as maturity dates, "will be fixed and agreed upon between E.F. Hutton and [Alpetco] at such times as the bonds are available for reoffering" and that the material terms will be subject to approval by the city. Once again, this provision obviously gives both the City of Valdez and E.F. Hutton the practical ability to opt out of the arrangement at any time, and negates any intention that the arrangement constitutes "commitments to lend or invest".

Moreover, the Hutton/Valdez arrangement is not an orthodox one. Normally, an underwriter agrees to purchase bonds and takes its chances on its ability to resell them on the open market, which it will hopefully do at a profit to itself. The arrangement contemplated in this case hedges Hutton's obligation to purchase the bonds and conditions it, for all practical purposes, upon a market for reoffering them, and pegs the terms of its purchase of the bonds upon market conditions that prevail at the time of reoffering.

In effect, Hutton's status as an underwriter, aside from administrative matters, does little or nothing to differentiate this arrangement from one in which the bonds were offered directly by Alpetco and/or the City of Valdez to the public. Therefore, since it is far from clear that the public will purchase the bonds, the arrangement cannot reasonably be regarded as a commitment to lend or invest at the present time.

The Thyssen Proposal. The second major component of Alpetco's purported compliance with the 1.5 billion dollar financing benchmark is its arrangement with Thyssen. Thyssen is a German corporation that is primarily in the construction business and which Alpetco expects to build the facility if it is built. Thyssen's "commitment" is set out in a letter dated December 7, 1979 to Alpetco, and a telegram dated December 17, 1979 that amplifies the December 7th letter. The letter provides that Thyssen does thereby "commit to arrange financing up to" $750 million subject to Alpetco's acquisition of an additional $750 million in financing. Definitive agreements for the financing "shall be entered into by December 18, 1980, on such terms and conditions as are customarily required for similar financings by lenders at such time. If such definitive agreements are not entered into by such date, we reserve the right to terminate our commitment hereunder without any liability on our part." The telegram substantially restates the above terms insofar as permanent financing is concerned.

On its face, this undertaking by Thyssen does not purport to be a commitment by it to lend or invest, nor a commitment by a third party to Thyssen to lend or invest to Alpetco. Clearly, Alpetco could not satisfy the requirement that it obtain a commitment to loan it money through a statement

that it would later arrange for a loan. By the same token, it cannot satisfy the requirement through a statement by a third party that it will later obtain a loan for Alpetco. In either case, the requirement is satisfied if, and only if, a commitment to loan money is made on or before the benchmark date -- December 18, 1979.

Moreover, even the limited undertaking by Thyssen to arrange for financing through some other party is subject to the prior requirement that the balance of the 1.5 billion dollars be committed. Since this obligation is conditioned upon an event that has not occurred, it cannot logically be argued that its own "commitment" was made on or before the effective date, albeit that the "commitment" would not satisfy the requirement of Subsection (d) in any event.

Even if it could somehow be argued that even though Alpetco has not obtained a commitment to lend to or invest money in its project, it has nevertheless, by virtue of its arrangement with Thyssen, "cause[d] contractually bound third parties to obtain written commitments to lend or invest...." Clearly, the obvious import of this language is that the "contractually bound" third party must obtain the commitment within the benchmark period, not that it merely have undertaken to do so within the benchmark period.

However, even if an agreement with a third party made within the allowable time period to obtain a loan commitment after the deadline is sufficient, it is probable that Thyssen is not "contractually bound" to do so, since the essential terms and conditions of the loan, including interest rate, repayment schedule, security, and all of the ordinary and customary provisions of a loan agreement are not set out in Thyssen's letter. This fact caused Mr. Bonness to conclude that the "lack of specificity most likely would result in a court concluding the commitment is not enforceable against Thyssen." See page 9 of the memorandum to Commissioner LeResche dated February 21, 1980. Consequently, the Thyssen arrangement is deficient under subsection (d) in two respects, and it is highly questionable whether Thyssen is a "contractually bound" third party, even if the nature of its undertaking is otherwise sufficient.

Somehow, Mr. Bonness concluded that even though the undertaking of Thyssen was probably not enforceable, it was sufficient to comply with subsection (d). Insofar as the nature, as opposed to the enforceability, of Thyssen's undertaking is concerned, Mr. Bonness stated only that

> "I believe that a commitment 'to arrange' is satisfaction of Alpetco's requirement 'to obtain' if the commitment is otherwise adequate. It is not surprising to find a lead company willing to take on the obligation to come up with the financing without knowing a year in advance exactly who will provide the funds."

With all due respect, for the reasons set out above, I think this conclusion is erroneous. A "commitment" by a construction company of undetermined financial position to "arrange" that another party make a loan on unspecified terms, a "commitment" which is in itself of dubious enforceability, can hardly be equated with a commitment by a lender to lend money. The fact that Alpetco is having difficulty in obtaining financing and does not know at this point who its ultimate lenders will be (if any can be found) does not detract from this conclusion.

The precise purpose of subsection (d) was to ensure that the State not be committed to the Alpetco project unless Alpetco could demonstrate its feasibility by obtaining the necessary financing commitments within the 18-month period designated. It would be an exercise in totally circular reasoning to conclude that Alpetco's inability to obtain the financing relieves it from the obligation to do so, and that it is therefore entitled to the fruits of the contract without performing its own obligation.

LAW OFFICES
WOLF POPPER ROSS WOLF & JONES
845 THIRD AVENUE
NEW YORK, N.Y. 10022

PLAZA 8-4600 CABLE "WOPOROW" NEWYORK

May 20, 1980

Joint Gas Pipeline Committee,
Alaska State Legislature

Hon. Bill Miles, Co-Chairman
Hon. Terry Gardiner, Speaker of the House
c/o Legislative Affairs Agency
Pouch Y, State Capitol
Juneau, Alaska 99811

Gentlemen:

We transmit to you herewith the Memorandum called for by the Agreement between the Legislative Affairs Agency, on behalf of the Committee, and my firm.

In the enclosed Memorandum, we have discussed and rendered our opinions as to whether ALPETCO has been and is now in compliance with its Royalty Oil Contract with the State of Alaska, and whether the determination of the Commissioner of Natural Resources to that effect may be judicially reviewed.

We hope that you will find our analysis useful and responsive to your inquiry; and we remain ready to respond to any further or additional inquiries that you may have.

We are pleased to have been able to be of service.

Yours truly,

ERIC L. KEISMAN

ELK:rd
Enclosure

AGO 559812

MEMORANDUM May 19, 1980

TO: Joint Gas Pipeline Committee Of
The Alaska State Legislature

REP. Bill Miles, Co-Chairman
REP. Terry Gardiner, Speaker Of The House

FROM: Eric L. Keisman
For Wolf Popper Ross Wolf & Jones

I. Introduction

This Memorandum is in response to your request that we review and express our opinion as to certain questions arising under an agreement between the State of Alaska and The Alpetco Company, ("ALPETCO") entitled "Agreement for the Sale and Purchase of State Royalty Oil," executed February 22, 1978 ("the Royalty Oil Contract"). This contract, originally entered into between the Alaska Petrochemical Company ("Alaska Petrochemical") and the State, was amended on May 17, 1978 and thereafter approved by the required concurrent resolution of the Alaska State Legislature, as of June 18, 1978.

In essence, the Royalty Oil Contract provides for the sale and purchase of certain crude oil received in kind by the State as royalty under other agreements and leases, and for the construction and operation in Alaska, by the purchaser, of a "petrochemical manufacturing and fuels refining facility...with capacity to process at least 150,000 barrels of crude oil per day," (Art. 4.2.1).

On or about December 13, 1979, Alaska Petrochemical, Charter Oil (Alaska), Inc. ("Charter") and E.F. Hutton (Alaska), Inc. ("Hutton") entered into the "Alpetco Joint Venture Agreement," creating The ALPETCO Company ("ALPETCO"). On December 13, 1979, Alaska Petrochemical assigned its interest in the Royalty Oil Contract to ALPETCO. The assignment was accepted on behalf of the State by the Commissioner of Natural Resources ("the Commissioner").

In order to ensure full and timely compliance by ALPETCO of its obligation to construct and operate the "Petrochemical Facility" required by Article 4.2.1, it was required, by Article 10.2, to achieve particular items of progress by particular times after the Effective Date. Article 10.2 provides that the "Agreement shall terminate upon failure of Buyer [ALPETCO] to take each and every one" of the specified actions "within the time specified for each...."

In stated demonstration of its compliance with the provisions of Article 10.2(3) ("the Eighteen Month Benchmarks"), ALPETCO made certain submissions in writing, to the Commissioner, on December 13, 1979; and, after a meeting on that date, made supplemental submissions on December 17, 1979.

On December 18, 1979, the Commissioner, stating that he was unable to determine whether or not there had been compliance with Article 10.2(3), wrote to ALPETCO granting it a six-month extension of time to comply, as permitted by the last sentence of that provision. (Letter, Commissioner LeResche to Gordon Cain, Dec. 18, 1979). However, on February 9, 1980, on the basis of the submissions made to him on or before December 18, 1979, the Commissioner again wrote to ALPETCO, declaring that he he had found it to be in full compliance with all provisions of Article 10.2(3). Earlier, on December 27, 1979, Governor Jay Hammond had announced his conclusion that ALPETCO had complied with that Article. Nonetheless, on April 28, 1980, the Commissioner again wrote to ALPETCO that certain matters had come to his attention that made it questionable whether it had been,or was, in compliance with the Eighteen Month Benchmarks.

At the time it made its submissions regarding compliance with Article 10.2(3), ALPETCO also gave notice that it was calling for initiation of delivery crude oil, pursuant to the provisions of Article 2.2, as amended. That Article allows such a call for delivery, prior to commencement of operation of the Petrochemical Facility, after ALPETCO "has obtained the financing commitment referred to in Article 10.2(3)(d) and has furnished satisfactory evidence of same to" the State, but also provides that it shall not be entitled to such delivery until it has "actually expended at least $100 million in Total Project Costs" and "at least twenty-five (25) months have passed since the Effective Date."

We have been requested to discuss and express our opinion as to:

(1) Whether ALPETCO has been, and is now in compliance with the Royalty Oil Contract; and

(2) Whether there are grounds for objection to the determination by the Commissioner that ALPETCO was, and is in compliance with that contract.

Our consideration of these issues focuses on ALPETCO's asserted compliance with Article 10.2(3); although certain of the issues discussed also bear on possible breach of other provisions, and on ALPETCO's satisfaction of the prerequisites to its entitlement under Article 2.2 to call for the initiative of delivery of oil.

In connection with this matter, we have reviewed all written materials submitted to us, including the Royalty Oil Contract, its amendments and the Legislative approval resolution; the ALPETCO Joint Venture Agreement; the written submissions of ALPETCO to the Commissioner under letters of December 13, 1979 and December 17, 1979, including all enclosures; transcripts of hearings before cognizant committees of the Legislature in March 1978 and in April 1980; ALPETCO's "Updated and Revised proposal of February 7, 1978; ALPETCO's publication entitled "Petrochemicals in Alaska -- The ALPETCO Story", dated March 15, 1980; the House Royalty Oil Committee Report, dated as of April 27, 1978; various memoranda of consultants and staff prepared for or submitted to the cognizant committees; legal memoranda prepared for the Commissioner by Frederick Boness, Esq., dated November 9, 1979 and February 21, 1980; a legal memorandum prepared for the Joint Gas Pipeline Committee by John M. Davis, Esq., dated April 23, 1980; an opinion letter of Lazard, Freres & Co., to the Commissioner, dated March 20, 1980; and miscellaneous background materials.

We understand it to be desired that we consider the issues in the light of a possible judicial, as well as legislative, determination; and have done so. It should be recognized that, while we consider our conclusions fully supported by the facts known to us, and the applicable law, our opinions cannot be taken as a firm prediction of the outcome of a possible judicial proceeding.

II. Has ALPETCO Compiled With Article 10.2(3) Of The Royalty Oil Contract?

It is our view that a strong and correct case exists that ALPETCO has not compiled with the provisions of Article 10.2(3), the "Eighteen Month Benchmark Provisions". This is so as to certain of the significant benchmarks aimed individually, and also, if they are considered collectively, as interrelated conditions. Article 10.2 appears to have been drawn to require ALPETCO to satisfy concerns of both the executive branch and the legislature as to the viability of the project and ALPETCO's ability to complete it. Thus, while a court might incline to find compliance on borderline facts as to a single condition, the converse could well be true if there was serious doubt on the record of compliance with several. A court should interpret provisions of this nature so as to give effect to their general purpose. 4 Williston, The Law of Contracts, § 619 (Third Ed. 1961).

A. Certain General Principles of Law.

The first frame of reference for testing ALPETCO's compliance with the benchmark provisions is, of course, the language of the Royalty Oil Contract itself. Cernohovsky v. Northern Liquid Gas Co., 68 N.W.2d 429 (Wis. 1955) ("The language of a contract must be understood to mean what it clearly expresses. A court may not depart from the plain meaning of a contract where it is free from ambiguity".) Were the language of the Royalty Oil Contract clear and unambiguous, that would end our inquiry as to meaning of the contract provisions, and all that would remain would be to test ALPETCO's performance against the meanings thus derived. However, certain of the provisions of Article 10.2(3) are not clear and unambiguous. By way of example, there is no single, clear legal meaning for such terms contained in Article 10.2(3)(d) and (e) as "commitment", "interim financing", or "written commitments to lend or invest". Similarly, Articles 10.2(3)(b) and (c) are not self-defining. A court will thus consider extrinsic evidence to determine the intent of the parties as to the meaning of such terms and provisions. Kincaid v. Kingham, 559 P.2d 1044 (Alaska 1977); Hendricks v. Knik Supply, Inc., 522 P.2d 543 (Alaska 1974). Probably the most significant extrinsic source, where it exists, is a contemporaneous statement by one of the parties to the

contract as to his understanding of its meaning -- see Port Valdez Co. v. City of Valdez, 437 P.2d 768 (Alaska 1968); Hendricks v. Knik Supply, Inc., supra, -- particularly where that contemporaneous statement is not contradicted by another party. In some instances, a statement by a party acknowledging his understanding of an obligation assumed by him is, in addition to being extrinsic evidence acceptable under the parol evidence rule, an admission -- and thus a very strong form of evidence. See Weinstein, Evidence (1979), ¶ 801 (d)(2)[01].

It should be noted, however, that parol evidence may not be introduced or considered to vary or to contradict the meaning of an agreement which is clear on its face. National Bank of Alaska v. J.B.L. & K of Alaska, Inc., 546 P.2d 579 (Alaska 1976).

Another source for the resolution of ambiguous terms in a contract is reference to the generally accepted meaning or meanings of such terms in the business or commercial community. See, Chase Manhattan Bank v. First Marion Bank, 437 F.2d 1040 (5th Cir. 1971). See also, National Bank of Alaska v. J.B.L. & K of Alaska, Inc., supra. This, however, is less weighty than more specific and objective expressions evidencing the nature of the agreement reached by the parties. 1 Corbin, Contracts, § 29 (1963) ("The parties may not give verbal expression to such vitally important matters as price, place and time of delivery, time of payment, amounts of goods, and yet they may actually have agreed upon them. This may be shown by their antecedent expressions, their past action and custom, and other circumstances"). See also Hendricks v. Knik Supply, Inc., supra, ("[Intent] may be ascertained from the language and conduct of the parties, the objects sought to be accomplished and the surrounding circumstances at the time the contract was negotiated"). Where such specific evidence is lacking and there are no easily applicable general commercial standards, the courts will inquire as to what one placed in the shoes of the parties would reasonably have expected the agreement to mean -- the courts thus preventing one party from insisting upon an interpretation that is, in the court's view, unreasonable. Restatement of Contracts, § 230 (1932), cited in National Bank of Alaska v. J.B.L. & K of Alaska, supra, at 584. Where,

however, the party to be charged has clearly expressed his understanding of his obligations, it is much less likely that the court will look to meanings wholly extrinsic to, and detached from, the particular contract or transaction at issue. See Weinstein, supra.

Thus, in considering whether ALPETCO has complied with the Eighteen Month Benchmark requirements, its own statements and representations to the Legislature, or other public statements, as to what it understood them to be, play an important role. In addition, substantial significance should be given to any expressions by the cognizant legislative authority as to its understanding, particularly to the extent that those were made to ALPETCO representatives, and apparently agreed to, prior to legislative approval of the agreement.

An additional general principle of contract law bears upon the matters to be discussed herein, particularly ALPETCO's compliance with the financial commitment requirements of subdivisions (d) and (e), referred to as "binding commitments" in Article 10.3. See Draper, The Broken Commitment: A Modern View of the Mortgage Lenders' Remedy, 59 Cornell L.R. 418 (1974); Leben v. Nassau Savings and Loan Association, 337 N.Y.S.2d 310 (A.D. 1972). For an agreement, whether described as a contract or a commitment, to be binding it must as a general matter, be complete as to all material terms. See, Alaska Creamery Products, Inc. v. Wells, 373 P.2d 505, 510 (Alaska 1962); Western Airlines, Inc. v. The Lathrop Company, 499 P.2d 1013 (Alaska 1972). On the other hand, an apparent incompleteness is not necessarily fatal to the binding character of an agreement. See, Corbin, supra, § 29. Where terms left for future settlement are within definite and proscribed limits, or where the content of an omitted term may be ascertained by reference to an extrinsic standard, (such as a price, to be determined by a pricing formula) many courts will uphold the contract, and, in effect, supply or imply the missing term. See, California Lettuce Growers v. Union Sugar Co., 289 P.2d 785 (Cal. 1955); Biothermal Process Corp. v. Cohu & Co., 119 N.Y.S.2d 158 (Sup.Ct. N.Y. 1953, affirmed in part and reversed in part 126 N.Y.S. 1 (A.D. 1953), aff'd, 124 N.E.2d 323, 308 N.Y. 689.

Where one party has already tendered partial performance, the courts have shown some reluctance to strike down a contract for indefiniteness, with the degree of such reluctance depending upon the extent of such performance or other action in reliance upon the purported agreement. See, Morris v. Ballard, 16 F.2d 175 (App.D.C. 1926). See also, Fontainebleau Hotel Corp. v. Crossman, 286 F.2d 926 (5th Cir. 1961).

On the other hand, where major premises of a complicated contract, such as a construction or land development contract have been omitted, the court have generally declined to supply the missing terms. See, Willowood Condominium Ass'n Inc. v. HNC RLTY Co., 531 F.2d 1249 (5th Cir. 1926); Western Homes, Inc. v. Herbert Ketell, Inc. 236 Cal.App.2d 142 (Cal. 1965).

As expressed by a California court, in the recent case of Metropolitan Water District of Southern California v. Marquardt, 379 P.2d 28 (Cal. 1963):

> "[t]"the question is one of degree. . . whether the indefinite promise is so essential to the bargain that inability to enforce that promise strictly according its terms would make unclear the enforcement of the remainder of the agreement . . . each party may be required to accept a reasonable determination of the unsettled points, or, if possible, the unsettled point may be left unperformed and the remainder of the contract enforced."

On the whole, the authorities seem relatively clear that a court will not supply the bulk of the essential terms of an agreement; nor will it construe as a binding contract something which is no more than a memorandum evidencing an intention to arrive at a formal contract in the future. Alaska Creamery Products, Inc. v. Wells, 373 P.2d 505 (Alaska 1962). Further, where a contract is too vague, indefinite, or incomplete, many

courts have described it as an illusory agreement, or an agreement to agree; which are simply additional verbal formulations for the proposition that no contract has been arrived at. Western Airlines v. Lathrop Company, 499 P.2d 1013 (Alaska 1972).

B. Background: Purpose Of The Eighteen Month Benchmarks.

The meaning of the provisions of Article 10.2(3), and therefore the determination whether they have been complied with, will almost surely be sought by a court with reference to the expressed purposes for the inclusion of that Article in the agreement. From all of the materials we have reviewed, two separate but closely related purposes clearly appear. ALPETCO was required to show compliance with these benchmarks in order to demonstrate the credit worthiness and financial viability of the total project as well as to demonstrate that there was in fact a vi able market for the products to be produced by the petrochemical facility to be constructed.

It is clear that in determining to sell its royalty oil, a primary desire on the part of the State of Alaska was to obtain something more than a purchase agreement. Several proposals for agreements to purchase the royalty oil were submitted to the State by various entities; but ALPETCO was chosen, in essence, because it was willing to undertake to build a substantial petrochemical manufacturing facility in Alaska and to operate that facility during the period of the royalty oil agreement. This was recognized and emphasized by ALPETCO in, inter alia, its February 7 1978 "Update and Restatement of ... October 15, 1977 Proposal For The Purchase of Alaska State Royalty Crude Oil And Construction Of A Petrochemical Facility In Alaska" (hereafter, "February 7, 1978 Proposal").

For example, ALPETCO emphasizes that its proposal ensures that it "does not purchase any royalty oil until the petrochemical project is put together with sales contracts and construction financing in place." (¶ 1, emphasis added). Further, there are lengthy discussions of

the demand for petrochemicals, ALPETCO's petrochemical marketing plan, possible participation by major chemical companies, Japanese markets for petrochemical products, and alternate configurations for a petrochemical facility. In those discussions, ALPETCO represented that its analysis showed that:

> "An Alaska project using royalty crude oil as its principal feedback looks more economically attractive the more high value added products are produced. Accordingly, ALPETCO focused its efforts on production and market cases which would primarily produce high value-added petrochemical products." (February 7, 1978 Proposal, pp. 13-14) (emphasis added).

Manifestly, these assurances and reassurances were in reaction to the strong expressed doubts of responsible officials and legislators as to the viability of the ALPETCO proposal. For example, the House Royalty Oil And Gas Committee Report (House Journal Supplement, April 27, 1978), concluded, with respect to the economic feasibility of the ALPETCO project, that it could not overcome the "general economic disadvantage of Alaskan enterprise. . ." (p. 5). The Committee pointed out that all of its consultants unanimously disagreed with ALPETCO's optimistic outlook. It warned that, in order to maintain economic viability and overcome this disadvantage, a reduction in the price of the crude oil feedstock for the ALPETCO facility was likely; and characterized such a price reduction as "intolerable in light of forecasted high cost of crude coupled with its world-wide depletion in the future." (at pp. 6, 7)

The Comittee also expressed substantial doubt as to the market potential of Alaska-manufactured petrochemical products, due to existing crude oil surpluses on the West Coast of the United States, anticipated Mexican competition in that market, and an absence of real market potential in Japan. (House Report, pp. 7-9)

In view of these, and other doubts, the Committee unanimously recommended disapproval of the proposed ALPETCO contract.

The report of David M. Reaume to The Alaska Royalty Oil And Gas Development Advisory Board ("Reaume Report") is also illustrative. Among the pertinent passages of this report are the following:

> "There is substantial evidence available which makes questionable the project potential for a large scale refinery operation dependent upon an export market for a major porcion of its products. We are concerned that the threat of job loss and financial reversals may generate future political pressure aimed at maintaining an efficient refinery operation." (at p. 2)
>
> * * *
>
> "While we have not had an opportunity to quantify the cost disadvantage of all Alaskan refined products on the West Coast and elsewhere it is possible to get a rough idea of the order of magnitude of the disadvantage. Niall Trimble, principal economist for the Department of Community And Regional Affairs has estimated the per barrel (of crude) disadvantage at between $1.42 and $2.13 per barrel (i.e., between $75 million and $115 million per year for a 150,000 BPD refinery). Even if this estimate was too high by a factor of 2.0 Alaska would still appear to face imposing barriers to the profitable operation of an export oriented refinery." (at p. 5)

The Reaume Report specifically denigrated the possibility of a profitable operation of a petrochemical facility in Alaska noting that:

> "The factors which dictate against the profitable operation of a petrochemical plant in Alaska include: (i) high construction costs, conservatively estimated at between 25% and 40% above Lower Forty Eight Costs; (ii) weakening world markets for petrochemicals; and (iii) the threat of uniform federal regulatory treatment of petroleum and gas, whether moving in interstate intrastate commerce.
>
> * * *
>
> "While the Alaska construction costs differential is a well accepted fact of life, the realization of the weak market outlook for petrochemicals and the difficulty of operating in Alaska has only recently begun to encroach upon the Alaskan conscious. Professional opinion on the subject is not seriously divided." (at p. 7)

This section of the Report concluded:

> "The weight of expert opinion clearly supports the notion that the petrochemical industry has entered a period of slower, more hesitant growth and that Alaska is not an economic location for petrochemical manufacturing." (at p. 10)

As is further reflected in the transcripts of the testimony before the Committee on March 14, March 18, and March 20, 1978, serious questions were raised with respect to ALPETCO's real commitment to build and operate the world-class petrochemical facility it had promised, and whether it could economically do so. Members of the legislature repeatedly raised that question, and the question

whether, and to what extent, ALPETCO was required to produce solid commitments for financing by Article 10.2 of the proposed contract. ALPETCO's Chairman, Mr. Honig, and its attorney, Mr. Rogers, took pains to assure the legislators that ALPETCO expected to be able to manufacture and market petrochemicals, such as would be produced by a "world scale heavily petrochemical refinery" (Transcript, March 20, 1978, at 22), and thus, in order to comply with the Eighteen Month Benchmarks, ALPETCO would have to have its long-term financing in place, in realistic terms. (March 18 transcript, at 8-10.)

The significance of the Eighteen Month Benchmarks in providing assurance that Alaska would get what it had bargained for is further highlighted by the relationship between Article 10.2(3) and Article 2.2, as amended by paragraph 3 of the amendments of May 17, 1978. Compliance -- and demonstration of compliance -- with the permanent financing commitment provision, Article 10.2(3)(d) is the trigger to ALPETCO's right to take delivery of royalty crude, combined with compliance with the Twenty-Four Month Benchmark requiring actual expenditures of $100,000,000 (Art. 10.2). Manifestly, the State desired a high level of assurance that the facility for which it had bargained would be financed and completed prior to the time when ALPETCO was permitted to purchase oil. All of these concerns, of course, are directly reflected in the benchmark requirements.

Particularly, demonstrations of product and marketability are required by subdivision (3)(d), dealing with the requirement for drafting and negotiating sales contracts, delineating produce configurations, etc.; as well as by subdivision (3)(c), calling for the conclusion of a contract for the sale of at least 70% of the production of the facility to be constructed. Demonstration that the proposed project could indeed be financed is required by the interim commitment requirement of subdivision (3)(e), as well as by the requirement for long term commitments of up to $1.5 billion provided in subdivision (3)(d).

After the agreement was executed by the Commissioner, and while seeking the required approval of the Legislature, ALPETCO issued further assurances, in its March 15, 1978 publication "Petrochemicals In Alaska -

The ALPETCO Story". As to the financial benchmarks, it said:

> "ALPETCO will not purchase royalty oil unless and until it has obtained financing commitments for $1.5 billion, which clearly indicates that the petrochemical facility will be built.
>
> * * *
>
> "ALPETCO and the State have agreed to performance bench marks which are designed to measure the progress made by ALPETCO in building the petrochemical facility. Failure by ALPETCO to attain each and every benchmark results in a right by the State to terminate ALPETCO's contract. . . . The 18 month check point. . . is the most important one. This is the 'go/no-go' benchmark. If ALPETCO is unable to put together the project by the 18 month benchmark, the State may terminate the contract." (at p. 12)

In short, by these and other statements in its March 15, 1978 publication, ALPETCO made plain that it understood what it was expected to demonstrate. That is, compliance with the Eighteen Month Benchmarks was to demonstrate to the State, with a rather high degree of certainty, that, in both marketing the financial terms, ALPETCO had the project "put together". There is a further significant underlying concept, reflected both in ALPETCO's submissions and in the benchmark requirements themselves. ALPETCO was to demonstrate the firm commitment of third parties to participate in the venture. It was not required or expected merely to reaffirm its own determination, intention, or internal capacity. While the benchmarks require ALPETCO to do certain things itself, including, e.g., the actual expenditure of $10 million; it is also required to obtain commitments from others with respect to interim and permanent financing. Similarly, it is manifest from subdivisions (b) and (c) that it was to demonstrate that it could market the products the petrochemical facility was to produce, and show how

it was going to do so. (See March 15, 1978 submission, pp. 5-9, with respect to marketing; and pp. 9 and 10 with respect to financing).

C. The Specific Benchmarks

1. The Financial Commitment Benchmarks

We believe that a strong case can be made that ALPETCO has failed to comply with the provisions of Article 10.2(3)(d) and (e), the financial commitment bench marks. Further, we believe it probable that a court would so find, upon a fair interpretation of the factual record which we have reviewed.

Interim Financing

The interim financial commitment benchmark is Article 10.2(3)(e), which requires that ALPETCO shall:

> "Obtain a commitment or commitments for interim financing for the construction of the Petrochemical Facility."

In purported compliance with that provision, ALPETCO has submitted the following:

(a) Letters of Manufacturers Hanover Trust Company, dated December 10, 1979, and Chemical Bank, dated December 11, 1979, by which each, in virtually identical language, confirms that it will participate "in the amount of $75 million in such a $150 million facility, subject to our satisfaction with" eight enumerated conditions. These include (1) each bank's review of economic projections and underlying assumptions demonstrating the "viability of the project"; (2) "availability of guarantees and undertakings from various parties" with respect to project completion, construction, and cost overruns; (3) continuance in effect of the royalty oil contract, continued fulfillment of all contractual agreements and obligations, and "assurance that the Alaska petroleum reserves available to ALPETCO" are "adequate to support all project financing"; (4) the "final written form of the ALPETCO joint venture agreement"; (5) availability to ALPETCO of sufficient equity to complete the project as presently

contemplated"; (6) "sufficient collateral and undertakings . . . to assure repayment"; (7) the "availability from responsible lenders" of "a complete takeout for the interim bank construction financing"; (8) and the commitment of the other bank involved. Even beyond these stated conditions, each letter makes the undertaking "subject to our satisfaction with the above requirements and with any other matters that may become relevant from a banking point of view. . . ."

(b) A "commitment to arrange interim financing" should the bank financing "fail to materialize", given by one of the proposed providers of permanent financing, Thyssen Rheninstahl Pechnik GMBH ("Thyssen"). (See pp. 16-17, infra.).

(c) A proposal, appended to its December 13, 1979 submission, that "up to $600 million in interim funds for construction costs for items qualifying for tax exempt financing will be provided by serialized takedown of" the tax exempt bonds which are proposed to be issued by the City of Valdez as part of the permanent financing for the project, pursuant to Article 10.2(3) (d). (See pp. 18, 21, infra.).

Whether any of these items satisfies, in full or in part, the interim financing commitment requirement turns largely on the meaning of the term "commitment". In the context of construction lending, that term may mean little more than an expression of interest, but it more often means a binding contract, subject only to certain clear and determined conditions. See, e.g., Presney, "Lender Procedures In Construction Loans", Advising Illinois Financial Institutions (Illinois Institute For Continuing Legal Education 1978), Ch. 10 (1978).

It is clear that ALPETCO was not expected to produce the actual construction loan agreements; these not being required until December 18, 1980 (Art. 10.2(5)). However, it is also clear that something more than an expression of interest, or an illusory commitment, was expected. As counsel for the Commissioner advised (Memorandum, Boness to LeResche, November 9, 1979), "a major concern for the State will be that the commitment is indeed a firm commitment." (at p. 16) Boness pointed out that

any such commitment would contain "certain basic elements" if it were to be judged legitimate. These would include the loan amounts, and indication whether secondary or contingency funds were to be available; drawdown schedules keyed to construction time tables; interest rates, terms and repayment schedules.

As Boness later, and we submit correctly, advised the Commissioner, the Chemical Bank and Manufacturers Hanover Trust letters fall so far short of the mark that they require little discussion. (Memorandum, Boness to LeResche, Feb. 21, 1980, p. 10). No term of the loan "commited" is spelled out, except its gross amount. These letters are little more than an indication that each bank will participate in a loan, all of whose terms are yet to be determined, if, in its discretion, it considers it advisable to do so at some later date. They offer no assurance to the State as to the very matters over which serious concern was expressed prior to execution and approval of the Royalty Oil Contract. Rather, they make it clear that each bank has not yet formed any opinion, as to the economic viability of the project. Further, quite beyond the broad specific conditions, or reservations, each bank requires that it be satisfied, in the future, as to "any other matters that may become relevant from a banking point of view".

While virtually all commitment letters contain a variety of conditions and escape clauses for the lender, these letters are so utterly wanting in terms and details that they do not even meet the degree of specificity customarily found in simple construction loan commitment agreements for residential construction. Compare, Presney, supra, at p. 10-49. It is thus very likely that a court would hold that these letters are not the commitments called for.

The Thyssen backup "commitment" was seemingly obtained after the Commissioner indicated dissatisfaction with the bank letters, although this is not perfectly clear. (Letter ALPETCO to LeResche, December 17, 1979, p. 1, ¶ 1). By this letter, ALPETCO transmitted Thyssen's revised commitment with respect to overall financing, as well as its new commitment "to arrange interim financing." As a "commitment", this undertaking by Thyssen suffers from all the infirmities of its commit-

ment with respect to long-term financing, discussed in the next section of this memorandum. In the context of the interim construction financing requirement there is an additional weakness. Art. 10.2(3)(e) requires ALPETCO itself to obtain the required interim financing commitment or commitments. By contrast, subsection (d) allows it to obtain the commitments required itself, or to cause "contractually bound third parties" to do so. Reading the two clauses together, it appears that under subdivision (e), ALPETCO was to obtain direct commitments from the lender or lenders, not the promise of a third party to obtain them.

Despite the "binding commitment language of Article 10.3, it has been suggested that the commitments called for by subdivision (e) were to be something less than a binding contract, because ALPETCO was not required to execute "definitive documents" until the 30-month point. However, the "definitive documents" provision (Article 10.2(5)(a)) refers only to the long-term loan of funds, and not to the "interim financing." It is the fact that construction lenders generally require that a commitment for permanent financing be obtained as a condition to closing the short term, or construction and development loan on a project. See, e.g., Draper, The Broken Commitment: A Modern View Of The Mortgage Lender's Remedy", 59 Cornell L.Rev. 418 (1974). However, this does not mean that the construction lender's commitment, though subject to that and other conditions, is not, customarily, a binding contract. Quite the contrary, as llustrated by numerous authorities enforcing or granting damages for breach of commitments to lend money, it is by far the more common practice, in modern transactions, to cast a construction lending commitment in the form of an enforceable contract. See, e.g., Walter E. Heller and Co. v. American Flyers Airline Corp., 459 F.2d 896 (2d Cir. 1972); Avalon Construction Corp. v. Kirch Holding Company, 256 N.Y. 137, 175 N.E. at 651 (1931). Similarly, where borrowers have reneged, it has been recognized that a lender may be entitled to retain a commitment fee as liquidated damages for the breach of a commitment to lend. See, e.g., Regional Enterprises Inc. v. Teachers Insurance And Annuity Association, 352 F.2d 768 (9th Cir. 1965); White Lakes Shopping Center, Inc., v. Jefferson Standard Life Insurance Co., 208 Kan. 121, 490 P.2d 609 (1971).

Thus, based on the apparently reasonable expectations of the parties, and on the customary meaning of commitment in the context of construction and mortgage lending, the stronger view is that the interim financing commitment required under subsection (e) is a commitment which is a legally binding contract -- even though possibly one subject to numerous, or even onerous conditions. Due to the absence of virtually all of the material terms required to make a promise into a contract, we believe that a court should find that Thyssen had not entered into such a commitment.

The third item in ALPETCO's submission regarding compliance with subsection (e) is its proposal to utilize the proceeds from the issuance by the City of Valdez of economic development bonds for construction costs for those items within the total project qualifying for tax exempt financing. (These are the same bonds which are to be part of the permanent financing required under subdivision (d). From our review of the materials submitted to us, it does appear that the parties had long contemplated the use of such economic development bonds as part of the lending or investment package required for the overall construction of the petrochemical facility. Further, we find no strong reason to question the opinion of Messrs. Kutak, Rock & Huie that the use of such bonds, with a serial takedown during construction, as well as for long term financing, is customary. Further, such use is clearly contemplated by the relevant City Ordinance (Ordinance No. 7917), by Resolution No. 7953, and by the letter of Mayor Walker to ALPETCO. The principal difficulty with this element of the construction financing, (apart from the weakness of the underwriting commitment which supports it, see pp. 29-30, infra.), is that it is limited to the acquisition, development and construction of so much of the facility as may be financed by tax exempt bonds. While we are acting neither as bond counsel, nor as tax counsel, it seems clear even from the Kutak, Rock & Huie opinion that the tax exempt bond proceeds may be used only to "finance a portion of the construction costs of ALPETCO's proposed refinery and related facilities...."

There thus appears to be a substantial gap in the interim financing package, a gap which ALPETCO has

recognized. In its December 13, 1979 submission immediately preceding the documents submitted relating to subdivision (e) compliance, ALPETCO states the intention to make equity capital contributions in place of some of the proposed interim financing.

This, in turn, raises another serious problem of contract compliance: the equity contribution proposal, the Thyssen "commitment to arrange" interim financing and, to a lesser degree, the proposed development bond utilization, could well be viewed by a court as an offer of "substituted performance" for the performance actually called for by the Royalty Oil Contract. Under some circumstances, such performance may be acceptable compliance with a contract; and a court would generally find it so where the party entitled to performance manifests acceptance. Here, however, the agreement required strict adherence at least to all material terms and conditions (Article 17). Article 22 provides that the contract,

> "...may be supplemented, amended or modified only by a written instrument duly executed by the parties...after proper authorization including approval by the Alaska Royglty Oil & Gas Development Advisory Board, and the Alaska State Legislature."

This procedure has plainly not occurred, whatever effect may be given to the Commissioner's letter of February 9, 1980. (See Part III, infra.).

There is thus a strong argument that ALPETCO's "substituted performance" does not comply with the terms of the Royalty Oil Contract but is rather an improper and ineffective attempt at amendment or modification of that Contract. The very purpose of subdivison (e) was to require a demonstration of the credit worthiness of the project. If the interim financing can be obtained only by equity capital contributions from ALPETCO itself, or from its constituent companies, this is a demonstration of quite the reverse. Further, the Thyssen backup "commitment to arrange" is quite at variance from the actual, direct commitment from a lender -- and does not appear contractually binding, on the basis of its great lack of completeness. The bond utilization concept, even to the extent it may

be valid, does not appear to be fully responsive to the requirements of subdivision (e), which can reasonably be held to call for separate interim financing. As to this last item, there is significant doubt, however. It is not clear from the text, as no precise dichotomy is drawn between interim and permanent financing. Subdivision (d) does not contain the term "permanent".

Thus, a court could determine that items submitted in satisfaction of subdivision (d) may also satisfy in part, subdivision (e). But there is also a strong argument that in order to give subdivision (e) some independent meaning, ALPETCO was required to demonstrate the availability of some separate interim construction lending. On balance, it is our opinion that it has not done so; and that a court giving due weight to the language and purposes of Article 10.2(3)(e) should find that ALPETCO has not complied, nor demonstrated compliance, with its provisions.

Total Project Cost Commitments

The overall financial commitment benchmarks is Article 10.2(3)(d), which requires that ALPETCO shall:

> "Obtain or cause contractually bound third parties to obtain written commitments to lend or invest at least one billion five hundred million ($1,500,000,000) in the aggregate for payment of Total Project Costs."

There are three separate components to the submission made by ALPETCO as compliance with this requirement:

(1) The Thyssen Component. The firm of Thyssen, Rheinstahl, Pechnik GMBH ("Thyssen") issued a commitment to ALPETCO "to arrange financing of up to US $750,000,000... to cover cost for the engineering, equipment, materials, construction and other services required for the project", subject to certain conditions, by letter dated December 7, 1979. This was supplemented, on December 17, 1979 by a telex, restating the commitment and withdrawing certain of the conditions. At the time of the original letter, there was submitted a letter of reference of the Deutsche Bank A.G., dated February 9, 1978, attesting to Thyssen's capacity in such projects, and declaring the bank's opinion that Thyssen was capable of accomplishing and financing "the projects it undertakes...." At the same time, ALPETCO

submitted a contract, of December 7, 1979, between ALPETCO on the one hand, and a joint venture found by Thyssen and the Foster Wheeler Energy Corporation, for the construction of the crude oil refinery and petrochemical facility. The latter contract is recited as the consideration for the Thyssen financing commitment.

(2) The City of Valdez Component. ALPETCO has submitted the commitment of the City of Valdez, Alaska, to issue up to $600 million in tax-exempt economic development bonds, the proceeds of such issue to be loaned to ALPETCO, pursuant to the terms of Ordinance No. 7917, of the City of Valdez, creating Article 2, Chapter 9 of the Valdez City Code, entitled "Economic Development Bonds." Pursuant to that ordinance, the City of Valdez further enacted Resolution No. 7953, providing for the issuance of such bonds. The Mayor of Valdez subsequently executed a commitment letter to "loan or otherwise provide up to $600 million or such additional amount as shall be deemed necessary...." Additionally, Hutton's parent company, the firm of E.F. Hutton, issued letters confirming "its commitment to purchase from the City of Valdez" economic development bonds in the amount of up to $600 million." Each of these, and particularly the E.F. Hutton letter, are subject to certain conditions which will be discussed below.

(3) The Equity Capital Component. The partners of ALPETCO -- Charter Oil, Alaska Petrochemical Hutton -- issued letters of commitment to provide "equity funds" in the gross amount of $350 million for payment of total project costs. These commitments were in turn confirmed by the letters of the companies which were in turn the parents and/or shareholders of each of the ALPETCO partners.

Particularly due to the weakness of the Thyssen component, there is a very strong argument that ALPETCO has not complied with the conditions of Article 10.2(3)(d). Under the Royalty Oil Contract, it is clear that by December 18, 1979, ALPETCO was to have obtained, or to have "caused contractually bound third parties to obtain," binding commitments to lend or invest the funds in question. By virtue of Article 10.3 of the Royalty Oil Contract, ALPETCO was to have the right to withdraw from the venture if, "after expending all reasonable efforts" it had failed to obtain:

> "...the necessary binding commitments from interim and permanent lenders for all the funds necessary to permit construction of the Petrochemical facility under a loan or loans providing for repayment of such loans during the life of this Agreement...."

We believe that the clear import of this provision is that it refers to the Eighteen Month Benchmark requirements. Had it been meant to refer to Article 10.2(5)(a) requiring ALPETCO to "execute definitive documents relating to the long term loan of funds", there would have been no reason for the use of the term "binding", or the term "commitment." It is clear from the scheme and order of Article 10.2 that "commitments" were to preceed the actual closing of loan, financing and investment agreements, the subject matter of the "definitive document" benchmark. The first question, then is whether Thyssen had entered into a binding commitment of any sort. We think it clear upon the face of the documentation, that Thyssen entered into a binding commitment of any sort. We think it clear upon the face of the documentation, that Thyssen had not contractually bound itself to lend or invest funds. There is no indication in the materials submitted to us, that it was ever contemplated that Thyssen itself be the lender, investor, or other provider of such funds. Rather, it has always been made plain by ALPETCO and its representatives that Thyssen was intended to obtain the funds elsewhere. Even before Thyssen became involved in the project, ALPETCO made it clear that it did not expect the prime contractor to self-finance the construction. In "Petrochemicals in Alaska", supra, it said:

> "The project will be financed by a combination of bank revolving credit, medium and long-term debt, both taxable and tax-exempt, supplier credits and foreign export bank financing. The long-term taxable debt will be supplied by private placement issues with major life insurance companies, pension and profit-sharing and retirement funds. The tax-exempt portion of the project, which could include as much as $350 million, will be placed with casualty insurance companies and commerical banks." (pp. 9-10)

That Thyssen itself was not conceived to be the lender, or investor, was made abundantly clear by ALPETCO's own counsel (Jim Frances) and its financial vice president, (Willard Hanzlik), in their testimony before the Joint Gas Pipeline Committee, on April 28, 1980. (Transcript, pp. 70-87). While this testimony is in many respects vague, if not confusing, it is clear that Thyssen intends to obtain the funds at issue through the use of export credits, originating with the governments of the various countries in which equipment, etc., may be purchased. These governments would guarantee loans to be made by lending commercial banks and other institutions. We thus believe that it is clear that Thyssen is not a party who has made a commitment to lend or invest. Rather, the clear import of Thyssen's commitment, and of the testimony is that Thyssen is, at best, a "third party" who was to obtain commitments to lend or invest. The next question, then, is whether Thyssen is in any sense contractually bound. If so, what was it contractually bound to have done by December 18, 1979?*

It can be strongly argued that Thyssen is not contractually bound to do anything. Parties may exchange promises, and fully intend to create a contract, and yet still fail to do so. See, generally, 1 Corbin, Contracts, § 29 (1963).

The Alaska law with respect to the enforceability of agreements appears to follow the law of other jurisdictions, including the major commercial states. In Alaska Cremerary Products, Inc. v. Wells, 373 P.2d 505 (Alaska 1962), the Court wrote:

> "Any contract to be enforceable must be reasonably definite and certain as to its terms. To be final, the agreement must extend to all the terms which the parties intend to introduce and material terms cannot be left for future settlement. Unless the court has before it ascertainable provisions of an agreement, there is no contract upon which it may act." (At 510)

---

* Or, by the time the extension granted by the Commission was to expire.

In that case, the Court refused to enforce a purported contract for the sale of trucks, in the absence of an ascertainable terms with respect to the amount of the down payment, and the note to be given for the balance of the price. The transaction there was, of course, far more simple than the one involved in the present case. Thus, while the court indicated that it would be willing to imply "ascertainable provisions", even if there was some absence of precision and explicitness, it is difficult to see how a court could imply into the Thyssen commitment all of the terms that are omitted from it.

In Transamerica Equipment Leasing Corporation v. Union Bank, 526 F.2d 273 (9th Cir. 1970), the Court, apparently following California law, held a purported contract unenforceable where the parties had not resolved the question of which party would receive first payment from the oil wells which were to serve as loan security, the question of the method of payment of the proposed lending bank's fee, and the determination of a repayment schedule. See also, Willowood Condominium Ass'n, Inc., v. HNC RLTY Co., 531 F.2d 1249 (5th Cir. 1976).

In this instance, the only term of Thyssen's commitment which is specified beyond the conditions relieving it of the commitment, is the gross amount of the financing to be arranged. The commitment self contains no other substantive provision. Wholly absent are provision describing the ultimate source of funds; the type of financing; disbursement, take-down or repayment schedules; interest rate or rates (or standards for determining them), security provisions; or any other term or condition of what would necessarily be very complex commercial agreements. There are, of course, cases where, to save a contract it would be inequitable to strike down, a court has implied a missing contract term. Typically, these are transactions where the missing term may be easily ascertained, or implied, by reference to some extrinsic standard. For example, if, in a form residential mortgage, the lending bank has omitted the mortgage rate, a court could well imply that rate with reference to other residential mortgages issued by the same bank, or other banks in the community, during the same time period. See, Sintenis, "Current Treatment Of The Non-Refundable Commitment Fee and Related Problems," 86 Banking Law Journal, 590 (1969). But a court will not

write a contract for parties who have failed to do so. At most, it will uphold an incomplete contract when its incompleteness can be remedied with reference to an easily ascertainable extrinsic source -- whether generated by the parties, or by general commercial practice in the relevant industry. See also, 1 Corbin, supra, § 96. Thus, we think it extremely likely that an Alaskan court would determine that the Thyssen commitment is not a binding commitment.

The argument may be raised that a binding commitment was not required, since, as has been pointed out, the Alaskan courts would interpret a contract in the light of what is commercially reasonable under the circumstances. See, e.g., Day v. A & G Construction Co., Inc., 528 P.2d 440 (Sup.Ct. of Alaska, 1974). This, however, flies in the face of the "binding commitment" language of Article 10.3. The Day case does not say that the court will substitute what it considers reasonable for what the contract before it requires.

Further, if a court were to seek to give the Thyssen commitment some substantive content, so that it could consider whether that implied content satisfied the State's reasonable expectations, it would face great difficulties. As just shown, it is rather obvious that the term "arrange financing" has virtually no substantive content. There is little help in any of the extrinsic evidence. At most, a court might conclude that Thyssen was bound to use its best efforts to arrange viable financing. See, e.g., Wood v. Lucy, Lady Duff-Gordon, 222 N.Y 88 (1917). The implication of such a "best efforts" obligation would not satisfy the plain requirement of subdivision (d). Even if, by virtue of such a commitment, Thyssen has become the "contractually bound third party", the Royalty Oil Contract calls for it to have obtained, by December 18, 1979, "commitments to lend or invest." The record does not show that then, or now, Thyssen has obtained so much as a single actual commitment. In their testimony before the Joint Gas Pipeline Committee, ALPETCO's representatives have made that clear. For example, Mr. Hanzlik, dealing with the "export credit financing" which he admitted Thyssen was still in the process of arranging, testified:

> "I mentioned the term, 5 to 7 years, and the draw down of these instruments typically are in progress payments as required to supply the equipment. So beyond that, we can't be more specific because Thyssen doesn't know whether it is going to be buying specific items of equipment in France or in Japan or Germany or wherever. Once it determines these things, then the respective export agencies will come forward and those pieces will be put into the puzzle." (Transcript, April 28, 1980, p. 78).

Mr. Hanzlik then admitted that he could not yet say what countries, what commercial banks, and what suppliers of equipment might eventually be involved. Further, it appears from that testimony that the export credit financing will only be available for equipment purchases. We see no evidence as to who is expected to provide, and on what terms, the long term credit, or investment, for the remainder of the total project costs, except for those which may be satisfied out of the tax exempt bonds, or that may be provided by the equity investment. In short, as far as the records shows, Thyssen had neither commited itself, nor had it obtained commitments, by December 18, 1979 -- and there is no evidence that this has occurred to this date.

The best argument available to ALPETCO in response to this is that Thyssen's commitment, and its agreement to submit a fixed-price bid for the project, are a satisfactory substituted performance. At numerous points in the record, ALPETCO and its representatives stress the size, competency, and financial power of Thyssen, when asked to deal with the question of the validity of its commitment.

However, the Royalty Oil Contract itself does not call for such a performance; and, unless all parties to the contract lawfully and properly have accepted an offer of substituted performance, it is our opinion that such a offer does not cure the non-compliance with subdivision (d). While the Commissioner of Natural Resources, on February 9, 1980, purported to "find" that ALPETCO was

in compliance with all of the Eighteen Month Benchmarks, he purported to do so on the basis that they had actually been complied with, and not on the basis that he had accepted a substituted performance. Further, since any such substitution like, any other modification or amendment, would appear to require the approvals mandated by Article 22, it is difficult to see how the Commissioner had any power to accept a substituted performance.

Lastly, in terms of the purposes of the financing bench marks, the Thyssen commitment certainly provides no evidence of the willingness of third parties, particularly financial or other lending instiutions, to participate in financing the venture. At best, it provides an assurance that the general contractor, Thyssen/Foster Wheeler, will use its best efforts to make the project, which it desires to build, operative. Even that is a very qualified reassurance, in the light of the numerous conditions upon which Thyssen may withdraw.

The Valdez development bond component of ALPETCO's purported satisfaction of subdivision (d) is somewhat less subject to attack. Upon the materials we have reviewed, including the relevant Ordinance, Resolution, commitment letter of the City of Valdez, opinions of bond counsel, and the commitment of the proposed underwriter, E.F. Hutton, there is a likelihood that a court would find this portion of the financing commitment to be satisfactory. The use of tax exempt bonds as a portion of the overall financial package was in the contemplation of all parties from the early stages of the proceedings. During the 1978 hearings, there was clear testimony to that effect. See also, "ALPETCO in 1978 and ALPETCO in 1980: A Review", Joint Gas Pipeline Committee, April 28, 1980, p. 9. It may also be plausibly argued, that the definition of "Total Project Costs" in Article 1.13 implicitly recognizes the utilization of such a financing method. That Article does not in terms refer to the use of bonds, but does refer to expenditures or commitments for expenditures by "any city, borough or other governmental agency on any pollution control, sewage or water treatment, port, pipeline, terminal or other facilities, directly connected with or a part of the petrochemical facility, to the extent such facilities are utilized by the petrochemical facility." There is at

least an inference in this provision that tax exempt bond financing would be utilized, particularly if, as it appears to be the case, that would be the only practical way for a city or other unit to fund such expenditures.

However, there remain certain questions as to the validity of that commitment, in practical terms. We have seen no evidence that would indicate that the bonds could in fact be issued unless E.F. Hutton were to undertake their distribution. The Hutton commitment, as expressed in its letters of November 19 and November 21, 1979, is laden with conditions and cancellation rights, which create substantial risks that the purchase of the Valdez bonds by E.F. Hutton, and any syndicate it might form, may not take place. For example, the purchase and re-offering prices, maturities, and other material terms of the bonds are left open until the time of re-offering. Among the conditions so denominated, the requirement of condition (5) for the receipt from Standard & Poor's Corporation "of an investment grade rating on the bonds", and of condition (7) requiring ALPETCO to agree to commerically reasonable maturity schedules, interest rates, etc., create large areas of uncertainty. Moreover, Hutton has given itself the right to cancel its obligation if "any event shall have occurred which would adversely affect the business or earnings of the company or the feasibility of the project."

Thus, it cannot be said that the Valdez commitment, given the character of the E.F. Hutton commitment to repurchase, gives any major degree of reassurance to the State or Legislature that the issuance will actually take place upon terms and conditions rendering the entire project economically viable. In fact, the reservations thus expressed by Hutton seem to match the concerns which led to the insertion of the Eighteen Month Benchmarks. From this point of view, if the intent and purpose of Article 10.2(3)(d) alone were to govern, there would be a strong argument, because of the weakness of the Hutton commitment, that the Valdez commitment was also non-complying.

The difficulty with this argument arises from the usual nature of underwriting agreements. Particularly when dealing with a potential forfeiture, it appears, under such cases as the Day case, that an Alaska court will seek to place an "equitable" construction on the parties' expectations. This is the thrust of that line of Alaska authority which seeks to place a reasonable meaning, under the circumstances, upon contract language which may be ambiguously interpreted on its face. See, e.g., National Bank of Alaska v. J.B.L. & K of Alaska, Inc. 546 P.2d 579 (Alaska 1976).

If the parties contemplated the use of any publicly issued securities as part of the long term financing, then it is likely that, with regard to the question of the adequacy of an underwriting commitment issued by December 18, 1979, the court would necessarily look to the custom and usage of the financial community. It is the fact that fully binding, contractual underwriting agreements are not ordinarily given in advance, or far in advance, of the actual issuance of such securities. As one knowledgeable commentary puts it:

> "It is the unvarying practice of underwriters to delay the signing of the underwriting agreement... until only a few days (and frequently only a few hours) before the registration statement become effective...." (Wheat and Blackstone, "Guideposts for a First Public Offering, Business Financing (American Bar Association: 1963), at 57.

In effect, it is the custom of underwriters to refuse to be fully bound until just before the offering "goes effective." Even the final underwriting agreement, as described by Wheat & Blackstone, supra, generally includes most of the conditions and cancellation provisions contained in the Hutton commitment letters.

But the Hutton commitment may nonetheless be subject to attack due to its utter vagueness as to the

proposed terms, even within broad parameters, of any prospective offering. Wheat & Blackstone also point out that, long prior to the execution of an underwriting contract, and particularly where a complex undertaking is involved, it is customary to draw up an informal expression of the basic terms of the underwriting, which would include such matters as the underwriting discount (i.e. the spread between the purchase price and the re-offering price), and a formula by which the price to the public is to be determined. Here, only the gross amount of the issue or issues, and Hutton's conditions and privileges are actually specified. All of the material terms of the bonds are left open. While the investment banking firm of Lazard Frere & Co. has given the Commissioner its opinion that the commitments given were as firm as could reasonably be expected under all of the circumstances, this is by no means conclusive. (Letter, Lazard Freres & Co. to LeResche, March 20, 1980). One of the circumstances, not apparently considered, was the need and right of the State of Alaska to have reasonable assurances that the financing would go forward before permitting ALPECTO to purchase royalty oil. To the extent that a court would be willing to apply this criterion to the Valdez-Hutton commitment, there is a reasonable probability that it would be found wanting.

The final component of the total project financing is the commitment of the ALPETCO partners to contribute $350 million in equity capital. Again, these commitments are not entirely unequivocal, and, to the extent that after-occurring events may be considered, their reality may be seriously questioned. In the first instance, each of the owners of the ALPETCO joint venture has agreed to put up a proportionate share of equity capital. Charter Oil (Alaska) commits $245 million. Alaska Petrochemical Co., the original ALPETCO, commits $81.9 million, and E.F. Hutton (Alaska), Inc. commits $23.1 million. The commitments of Charter and Hutton are each confirmed by commitments of their respective parent companies. The commitment of Alaska Petrochemical is backed by its two shareholders, Seatrain Lines, Inc., and Alaska Interstate. In each instance, the commitment of the joint venture member is cross-conditioned on, and given in consideration of, the commitments of the other two joint venturers. Further, each of the equity contributors conditions its commitment

upon its approval "of the definitive documents relative to the long-term loan of funds for the ALPETCO project and to the execution by December 18, 1980, of such documents by ALPECTO and the lenders providing such funds."

These items, although they do create a degree of uncertainty in fact, are probably not sufficient to raise a substantial question as to the character of these commitments as "binding." In most ventures of this kind, the permanent financing is eventually put together as a "package", and that all of the constituent transactions are actually closed simultaneously, or are deemed so. Thus, it is not a strong basis for legal attack that such components are materially dependent.

Of course, the above only strengthens the argument that if any part of a component of the permanent financing is inadequate, the entire component will fall; and the benchmark is not complied with.

Somewhat more disturbing is the provision, in each of the co-venturers commitment letters, which reads as follows:

> "The above commitment of the undersigned is made solely for the purpose of assisting ALPETCO in satisfying the Commissioner of Natural Resources of the State of Alaska as to ALPETCO's compliance with Article 10.2(3)(d) of the Royalty Oil Contract."

On its face, this language could be taken to indicate a lack of intention to fulfill the commitment. For example, it could be argued that it reflects an intention, once the benchmark was deemed satisfied, to substitute some other source of capital for the equity commitments of the partners. On the other hand, it could be argued that the intent of that language was merely to make clear that no third party was intended to derive rights from the partners' commitments, but that these rights ran only to ALPETCO itself. But if that was the intended meaning, it is

hard to explain the language "satisfying the Commissioner... as to ALPETCO's compliance...." Finding nothing in the record which explains this language, we can only make the point that it casts some doubt upon the reality of the equity commitment.

Another significant factor in determining the validity of the equity commitment arises not from contractual language, but from the question whether it was adequately demonstrated that the parties making the commitment were capable of making the capital contributions promised thereby. We have not reviewed and analyzed the financial positions of the ALPETCO joint venturers, nor of their owners or parents. However, were the matter to be contested, it would be important to determine what data was submitted, or otherwise obtained, to demonstrate the actual ability of the partners to make the contributions commited. As a result of after occurring events, it appears that there was at least some lack of reality in the commitment of Alaska Petrochemical.

We have been informed last week, and have noted in press reports, that Alaska Interstate Co. has withdrawn from the ALPETCO joint venture, and that Alaska Petrochemical, the original contracting party, and a 75% owned subsidiary of Alaska Interstate, "is out of business" (Wall Street Journal, May 9, 1980, p. 24).

That article indicates that "financing uncertainties" were cited as the reason for withdrawal. We have further been informed that the remaining partners in ALPETCO, principally Charter, and Hutton, have agreed to a restructing of the equity financing to assume the withdrawn partners share. However, it is not possible to draw, at this time, any conclusion as to the legal significance of these events, in the absence of detailed documentation.

This chain of events does, however, cast doubt upon the continuing validity of the equity commitment. The Royalty Oil Contract itself is silent as to whether, if the Eighteen Month Benchmarks were complied with at a particular time, they may be substituted for by revised, or even entirely different, arrangements. The original joint venture agreement among the ALPETCO partners does contemplate the possibility of the withdrawal of one of

the venturers, and the continuation of the ALPETCO venture by the remaining partners. It could be fairly argued by ALPETCO that, in accepting the assignment of the Contract from Alaska Petrochemical to ALPETCO in the first instance, the State accepted the ALPETCO Joint Venture Agreement, in totality.

On the other hand, it could be argued with some force that, since none of the partners was required to assume the position of the withdrawing partner, and since the Eighteen Month Benchmark provisions were part of a single, continuing course of progress intended to lead to definitive financing, and closings of financial agreements, by December 30, 1980, the withdrawal of Alaska Interstate, and the "out of business" status of Alaska Petrochemical are a breach of the conditions of Article 10.2(3). In addition, this development with respect to the equity financing provisions adds still another element to the cumulative dubiousness of overall compliance with the financing requirement of subdivision (d).

In conclusion, then, it is our opinion that ALPECTO has not complied with the provisions of Article 10.2(3)(d), and that an Alaska court should so find. However viewed, the Thyssen commitment does not meet the applicable standards we have discussed. The Valdez bond component and the equity component are of doubtful validity, particularly in the light of the interest and purpose of Article 10.2(3). Considering the requirements of subdvision (d) as a unity, it is again our opinion that they have not been satisfied.

2. <u>The Marketing Benchmarks</u>

Article 10.2(3)(b) requires that ALPETCO:

> "Negotiate sales terms with prospective purchasers of products from the Petrochemical facilities; delineate product requirements, production ratios and quantities for the range of products to be produced from the Petrochemical facility; and draft contracts for the sale of products from the Petrochemical Facility."

Article 10.2(3)(c) requires that ALPETCO:

> "Enter into contracts for the sale of at least seventy percent (70%) of the product output from the Petrochemical Facility."

From the submissions made by ALPECTO to the Commissioner, it is by no means clear that it has complied with either of these provisions. With respect to the sales and contracting provisions of subdivision (b), ALPETCO has made no separate submission, relying entirely on its submission in proported compliance with subdivision (c), to wit, the Product Sales Agreement between Charter Oil (Alaska), Inc. and ALPETCO, dated as of December 1, 1979.

With regard to the product requirements, production ratios, and production quantity requirements, ALPECTO submitted a schedule showing the range of output of various fuel and chemical products, showing a total output of some 146,200 barrels per day; all as a portion of "Stage I" of its proposed operation. In addition, it briefly indicated further petrochemical product development for "Stage II" and "Stage III".

Plainly, subdivision (b) is open ended and imprecise in many respects. ALPETCO is only required to "delineate" its product and production plans. To delineate means "to trace the outline of; sketch out." (Webster's New World Dictionary, 1972). It would be difficult to argue that ALPETCO has not done at least that much. In addition, it appears that an outside consultant has rendered its opinion to The Division Of Minerals and Energy Management to the effect that ALPETCO's submission in this regard appears to be "consistent with the processing configuration chosen for the refinery", that is, with the materials submitted in compliance with subdivision (h) of the bench mark provisions. To this extent, then, and in the absence of any evidence to the contrary, we have not found a substantial basis for challenging ALPETCO's compliance with this portion of subdivision (b). However, recent events raise some doubt as to this compliance. On April 28, 1980, the Commissioner wrote to ALPETCO's general manager, raising a question whether a design change in the Petrochemical Facility, submitted to the Commissioner on April 9, 1980,

affected ALPETCO's "apparent compliance with Article 10.2(3)(h)...." To the extent that compliance with subdivision (b) turns upon compliance with subdivision (h), it is possible that this is once again an open question. Further, one of the purposes of subdivisions (b) and (h) was to provide assurance to the State, and to the Legislature, that the ALPETCO project truly comprised a "Petrochemical Facility." If the changes in product and plant configuration raise a doubt as to whether that is in fact the character of the facility, then, as an ALPETCO attorney has testified, there is an additional basis for asserting a breach of the Royalty Oil Contract. (Transcript, March 20, 1978, p. 22).

There is a stronger argument that the remaining provisions of subdivision (b) have not been satisfied. As the Commissioner has been advised, unless the sales and contracting provisions of subdivision (b) are to be read as wholly redundant with subdivision (c), then, in order to satisfy (b), ALPETCO should have made reasonable submissions to demonstrate what it has done, in terms of negotiation and the drafting of contracts, to market the output not to be purchased under (c). (Memorandum, Boness to LeResche, Nov. 9, 1079, p. 13). ALPETCO has declined to make any such submission relying on the "Product Sales Agreement" between itself and Charter, dated December 1, 1979, for its compliance with this part of subdivision (b), as well as subdivision (c). It is possible that a court would read these provisions as redundant of one another, but we consider that the better view is that they are not, and that a separate submission under (b) was required. As the matter stands, the State has been given no indication whatever, (other than vague and apparently now inoperative pre-approval presentations) as to how, and on what terms, ALPETCO proposes to sell the 30% of its output which is not sold under the Charter contract. In view of the previously discussed purposes of this benchmark, there is a strong argument that this is a material non-compliance with the condition. Further, it might not be inappropriate for the Legislature to raise the question whether the refusal to furnish information is a cover for the fact that such marketing efforts have been unsuccessful; which would in turn, raise serious doubt as to the economic viability of the entire ALPETCO project.

This doubt is compounded by the nature of the contract submitted as compliance with subdivision (c). This contract, between ALPETCO and Charter, its 70% owner, while not prohibited by the terms of (c), is, at the very least, a violation of its spirit and purposes. The purpose of subdivision (c) was manifestly to demonstrate that there was indeed an actual demand in the marketplace for 70% of the Petrochemical Facility output. It should not be necessary to belabor the point that the existing contract is a strong indication to the contrary. Particularly with the withdrawal of Alaska Petrochemical from the venture, it has become primarily the venture of Charter, with the co-venturers retaining a rather minor fraction of ownership and responsibility. ALPETCO's agreement to sell to its principal partner, which has the greatest stake in the continuation of the project, and the accural of the right to purchase Royalty Crude Oil, is at best a dubious method for demonstrating any real demand for the products it proposes to produce. It at least raises the question whether Charter entered into the sales agreement as a last resort, to preserve the venture, and in the hope of finding product markets at some time in the future. Since it would be in a position to achieve significant revenues from crude oil transactions for several years,this is not an improbable inference. In addition, we note that the probable product configuration outlined in the Product Sales Agreement calls for an approximate 80/20 division between fuels and petrochemicals. While no particular product configuration is required in the Royalty Oil Contract, we have noted the repeated representations of ALPETCO to the Legislature of a determination to maximize high value-added petrochemical output. As ALPETCO's attorney said, if ALPETCO were to totally depart from the concept advanced in obtaining Legislative approval, that is, the concept of maximizing petrochemical production, the State would have a strong case for cancellation. This 80/20 configuration may come close to the repudiation of the underlying understanding to which Mr. Rogers referred. (Transcript, March, 1978, supra, at p. 22).

Another issue is raised by the term of the Product Sales Agreement. It is to run for fifteen years from the "date of the first cargo loading after completion of the Refinery and Terminal." The Royalty Oil Contract does not on its face require that the 70% of production sales

contract or contracts must run for any particular term. However, the Boness Memorandum of November 9, 1979 argues persuasively that, in view of the relationship between the financing requirements of the project and the demonstrable saleability of its output, any such product sales contracts should either cover the "remaining length of the Agreement itself" or "the length of the loans (or bonds)." (At p. 15) The term of the Royalty Oil Contract is twenty-seven years (Article 10.1). Unless it is contemplated that twelve years will elapse between the Effective Date of that Contract and the "first cargo loading", the Product Sales Agreement does not appear to comport with "the remaining length of the agreement" standard. By virtue of Article 2.7, (added by paragraph 4 of the Amendments of May 17, 1978), it is clearly contemplated that a petrochemical facility with a processing capacity of 150,000 barrels per day will be in operation six years after the Effective Date of the Contract. Thus, a twenty-one year period of actual operation of the Petrochemical Facility during the term of the Royalty Oil Contract is plainly contemplated. There is thus a term of six years, more or less, as to which no binding contract of sale has been effected.

Applying the alternate standard suggested in the Boness Memorandum, supra, there is no indication whatever that the period of the Product Sales Agreement is co-extensive with the term of any loans or other debt financing that may be obtained for the project. At this time, on the record we have examined, there has been no determination as to the maturities, or time terms, of any such anticipated debt financing. Thus, there is no way to apply this standard for measuring the adequacy, in terms of time coverage, of the Product Sales Agreement. We believe that a court could, and should, determine that the provisions of subdivision (c) require the sale of seventy percent (70%) of product output from the time when such product output commences until the expiration of the Royalty Oil Contract. While (c) is not specific in that regard, this is the most logical reading. The legitimate concern of the State extends to sales of the facility's output throughout the term of that Contract; and no other or shorter term is expressed or implied in subdivision (c). Thus, unless there is factual material of which we are not presently aware, it is our opinion that there is a strong and substantial

argument that the Product Sales Agreement is not in compliance with (c); and that ALPECTO has thus not complied with either subdivisions (b) or (c).

3. Other Eighteen Month Benchmark Provisions

On the available record, we do not see a strong basis for challenging ALPETCO's compliance with the remaining Eighteen Month Benchmarks, except as may arise from the Commissioner's letter to ALPETCO of April 28, 1980.

With respect to Article 10.2(3)(a), the $10 million expenditure requirement, ALPETCO reported that it had expended, or commited to expend, a total of $11,377,229.98. It further submitted a letter of Peat, Marwick, Mitchell & Co., reporting on the verification procedures that firm had performed. While these did not amount to a full audit, a fair reading of (a) does not call for such an audit. All it requires is that in fact ALPETCO has expended or commited to expend the required sums. This being the case, and no evidence appearing in the materials reviewed by us to indicate that they did not, in fact, do so, we do not believe there is a basis for challenging their compliance with the subdivision.

Article 10.2(3)(f) requires that ALPETCO "complete and file an environmental impact assessment on the petrochemical facility." It appears that this was in fact done. (House Research Agency Memorandum, Brody to Miles, February 20, 1980, p. 10).

Article 10.2(3)(g) requires ALPETCO to "complete and file all material state, local and federal permit applications." It appears that, on September 27, 1979, the Commissioner transmitted to ALPETCO a list of the permit applications, both state and federal, which he deemed material within the meaning of this provision. We have not independently researched the question whether this list was correct; and do not consider that that was within the scope of the inquiry to us. It appears that there was no question raised as to the propriety of ALPETCO's submission in compliance with this subparagraph until April 28,

1980. At that time, the Commissioner wrote to ALPECTO, noting that the Alaska Pipeline Commission had filed an Order to Show Cause with respect to " a permit for your crude and product pipelines." The Commissioner's letter indicates that the Pipeline Commission noted that it had received no such application. We are not at present in a position to render an opinion at to whether that permit is "material" within the meaning of subdivision (g); and it was not apparently included on the list of material "state permits" transmitted to ALPETCO. Nonetheless, the Commissioner has raised the question whether the failure to file for this permit constitutes non-compliance with subdivision (g), and it may well be that further exploration of the surrounding facts and circumstances is in order.

Subdivision (h) requires that ALPETCO:

> "Complete plant design and oppimization necessary to obtain a definitive project cost estimate ('definitive' meaning a cost estimate containing no more than fifteen percent (15%) variance in anticipated costs)."

We are not in a position to independently render our opinion as to whether the materials submitted by ALPETCO satisfy this bench mark, as this would require particular expertise in engineering, project design, etc. However, we note that two apparently substantial questions have been raised.

Firstly, some members of the Legislature have inquired whether this bench mark required ALPETCO to have obtained, by December 18, 1979, the definitive project cost estimate. It is our opinion that this is not the case. The phrase "necessary to obtain" has implicit in it that the cost estimate is to be obtained in the future, and that the plant design and optimization is all that must be completed by the cut off date. It appears that the state has received the opinion of independent consultants that this work was in fact accomplished. (House Research Agency Memorandum, supra, at p. 10).

Secondly, the Commissioner's letter to ALPECTO dated April 28, 1980, raises the question whether the design change submitted to him on April 9, 1980, effects ALPECTO's "previous apparent compliance" with this provision. The raising of this question, we believe, calls for further factual inquiry.

Conclusion As To Article 10.2(3)

On the basis of the foregoing, we conclude that ALPECTO was not, on December 18, 1979, or thereafter, in compliance with all of the provisions of Article 10.2(3). More particularly, there is a strong case that it has failed to comply with the overall financing requirements of Article 10.2(3)(d), and the interim financing requirements of Article 10.2(3)(e). In addition, a strong case can be made for failure of compliance with Article 10.2(3)(b) and 10.2(3)(c), subject to the caveat that it is more difficult to measure what is called for by these subdivisions than it is to measure what is called for by the financing provisions, as a matter of legal interpretation of the relevant documents and evidence.

III. Is There A Basis For Challenging The Determination Of The Commissioner Of Natural Resources That ALPETCO Was, And Is, In Compliance?

On February 9, 1980, the Commissioner, in letter to ALPETCO, stated:

> "After thoroughly reviewing the documents submitted by you on or before December 18, 1979, I am of the opinion that the Alpetco Company, as the duly approved assignee of all of the rights of Alpetco Petrochemical Company under the Agreement...has timely fulfilled all the requirements set forth in Article 10.2(3)(a-h) of the Agreement, and that the Agreement is in full force at the date hereof."

It is our opinion that, under the law of Alaska, this opinion, or determination, is subject to judicial re-

view, and that such review can result in its being overturned, if the court were to decide that the Commissioner had exceeded his authority under the Royalty Oil Contract, or had failed to follow the intent of the legislature in interpreting the requirements of that contract. See, e.g., Moore v. State of Alaska, 553 P.2d 8 (Sup.Ct. of Alaska 1976) (concurring opinion of Rabinowitz, J., at 30-33); see also State v. Aleut Corp., 541 P.2d 730 (Sup.Ct. of Alaska 1975); K&L Distributors, Inc. v. Murkowski, 486 P.2d 351 (Sup.Ct. Alaska, 1971).

The authorities, however, are not entirely clear as to the standard of review that would be applied. The broadest standard is applied where the courts have been called upon to determine whether an administrative officer or agency has failed to follow the procedural requirements for making a determination. This was the standard applied in Moore v. State of Alaska, supra, and State v. Aleut Corp., supra.

A much more limited standard is applied where the courts are asked to review the substantive merits of an administrative decision, and the opinions generally state that the administrative determination will be upheld unless it is arbitrary and capricious, or lacking in a reasonable basis in the record. See Jager v. State, 537 P.2d 1100 (Sup.Ct. Alaska 1975); Swindel v. Kelly, 499 P.2d 291 (Sup.Ct. Alaska 1972); Mobil Oil Corp. v. Local Boundary Comm'n, 518 P.2d 92 (Sup.Ct. Alaska 1974).

The infirmities in the Commissioner's determination here are not, in the strict sense, infirmities arising out of failure to follow a specified administrative procedure. No specific procedure was set out in the Royalty Oil Contract for any such determination; nor is this the type of determination that appears subject to the administrative procedures statutes. In fact, that contract does not call for the Commissioner to make any determination, as such, under Article 10.2. By its terms, that Article provides for the Royalty Oil Contract to terminate of its own force if any of the various benchmarks provisions are not complied with. It appears that the Commissioner, on behalf of the State, would be required to assert the termination. In that sense, it is arguable that he was required to make such a determination -- but merely in an executive, as dis-

tinguished from a quasi-judicial, capacity. Similarly, under Article 2.2, ALPETCO was required to demonstrate its compliance to the satisfaction of the State. Thus, it is at least reasonable to infer that the Commissioner, on behalf of the State, was to decide and to notify ALPETCO whether such a demonstration had been made.

Given that such a power existed, even in the absence of provisions mandating a particular procedure for exercising it, the Court should, and probably would, at least require that the Commissioner adhere to the intent and meaning of the Royalty Oil Contract in testing compliance with the benchmark provisions of Article 10.2(3). This is particularly so since the approval of the Legislature was required as a condition to its effectiveness. A court could fairly determine that the Commissioner's adherance to such intention, as expressed in the benchmark provisions themselves, should be examined in the same manner as an administrator's compliance with statutes or regulations promulgated by, or under the authority of the Legislature. As the Court wrote in State v. Aleut Corp. supra:

> "...when determining questions of whether proper procedures were observed, whether the administrative agency has acted within the scope of its authority, or whether an agency's interpretation of regulations is consistent with the statutes on which they are based, we are not faced with problems involving specialized or administrative expertise." (541 P.2d at 736)

It is not unreasonable to expect that the court, in the present case, might indeed exercise its own independent judgment as to whether the Commissioner had interpreted Article 10.2(3) of the Royalty Oil Contract in accord with the Legislative intention, to wit, that the benchmark provisions be strictly enforced. While the Commissioner presumably has administrative expertise with respect to matters bearing specifically upon the leasing, sale or other disposition of natural resources, there is little basis for arguing that an administrative official has greater expertise than the court in interpreting a contract, or the provisions of a contract regarding obligations to obtain financial commitments, or to enter into particular types of commercial contracts.

Whatever standard of review might arguably be applied, it is at least clear that judicial review is not foreclosed; as nothing in the Royalty Oil Contract gives rise to any inference that the Commissioner's determination was intended to be final and unreviewable. Even if there were any such indication, this would not bar at least limited judicial scruinity. K&L Distributors, Inc. v. Malschik, supra.

Further, even if the court were to decide that the Commissioner should be sustained unless his determination was arbitratary and capricious, a reasonably strong case can be made that it should be overturned. There is evidence in the record we have reviewed that the Commissioner did not follow the applicable legal standards set forth in the memorandum opinions he received from counsel, that is, from Boness. He found ALPETCO in compliance with subdivision (b), in spite of the absence of any separate submission in compliance with the sales negotiation and contract preparation requirements of that subdivision. (Compare, Boness Memorandum, November 9, 1979, p. 13). He did not apply the standards set out, in the same memorandum, for considering whether the time period covered by the Product Sales Agreement constituted compliance with subdivision (c). (Boness Memorandum, supra, p. 15). Further, it is at least strongly arguable that he ignored the requirement that the commitments offered in satisfaction of the requirements of subdivisions (d) and (e) be "firm", i.e. legally binding, commitments. (Compare, Boness Memorandum, supra, pp. 15 - 17).

There is also some evidence in the materials we have reviewed that the Commissioner may have made his determination on the basis of advice that, should he uphold ALPETCO's compliance, he would not be overruled in a court challenge, rather than on the basis that actual compliance had occurred. (See Boness Memorandum, February 21, 1980, p. 10). Of course, whether or not this was actually the case could only be determined by further inquiry, in a judicial proceeding or otherwise.

A court would also probably overturn the Commissioner's determination if it found that he had determined to accept substituted performance with regard to such matters as, the Thyssen component of the permanent financing required under subdivision (d) of the Royalty Oil Contract.

As we have previously discussed, the provisions of Article 22 and Article 17 of that contract give rise to a strong argument that he had no power to do so, without returning to the Legislature for a new consideration and approval or disapproval. Of course, were the court to agree that the Commissioner had improperly accepted a substituted performance, it would follow that his determination was without legal effect, in that it was in and of itself a violation of the conditions of the Royalty Oil Contract, as approved.

Thus, while the matter is not without difficulty, there is a strong case that, even if a court were to apply the "arbitrary and capricious" standard, it could overturn the Commissioner's action. If the court were to determine, alternatively, that due to the nature of the Royalty Oil Contract and the Legislative approval required for its effectiveness, its interpretation by the cognizant administrator was subject to review for substantive correctness, then, for the reasons discussed in part II of this Memorandum, it is our considered opinion that it is highly likely that the determination of ALPETCO's compliance could be subjected to a successful challenge.

It is difficult to predict in advance the standard or review that would be applied, since the situation here is not precisely analogous to that found in the prior authorities. The standards of review the courts have articulated are not as crucial to the outcome of a particular case as they appear, on the surface to be. If a court can be persuaded that the admnistrator concerned has acted inconsistently with the fundamental purposes of the law or regulation he is administerng, there is a good probability of a successful challenge. Here, we think the better view is that the Commissioner's determination should be reviewed as not entitled to particular deference. He was not to make policy determination in reviewing ALPETCO's compliance with Articles 10.2(3) or 2.2. These had been made and expressed in the Royalty Oil Contract itself and in the Legislature's action thereon. He was not, as in other cases, to determine whether his findings were in the best interests of the State (Cf. A.S. 38.05,035(a)(14)). Rather, he was to see that the State received what it had already bargained for. Where he was bound so to act, there is a strong argument that a court need not defer to administrative expertise, but should fully exercise its competence to review the matter, if not

de novo, at least in a manner consistent with the concept that the judiciary has the greatest expertise in dealing with the legal and factual issues arising out of the making and performance of contracts.

Conclusion As To The Commissioner's Determination

The Commissioner's determination should be held subject to judicial review. The standard of review that would be applied is not clear from the case law. Whatever standard would be applied, there is a strong case that the determination of February 9, 1980 was inconsistent with the meaning and purposes of the Royalty Oil Contract; and was erroneous to such a degree as to warrant reversal.

Respectfully submitted,

WOLF POPPER ROSS WOLF & JONES

By: _____
ERIC L. KEISMAN

Rep. Malone

STATE OF ALASKA

THE LEGISLATURE

BUDGET AND AUDIT COMMITTEE

FINANCE DIVISION
POUCH WF-STATE CAPITOL
JUNEAU, ALASKA 99811
PHONE: (907) 465-3795

M E M O R A N D U M

DATE: May 8, 1980

TO: Honorable Bill Miles, Co-Chairman
House Resources Committee

FROM: Milt Barker, Fiscal Analyst MB
Legislative Finance Division

SUBJECT: Alpetco Refinery Cash Flow

Table 1 (attached) is a projection of the operating cash flow of the proposed Alpetco facility over the life of the 27-year contract with the state. It is a best guess, based on publicly available data including data released by Alpetco, yet subject to a great deal of uncertainty.

Three areas of greatest uncertainty are:

The spread between the market value of a barrel of product and the cost of a barrel of feedstock. This cash flow basically freezes this relationship as it existed in the spring of 1980 over the life of the project. Data published in "Petroleum Intelligence Weekly" seem to indicate that this spread has varied as much as $2.00 in the past two years, using contract prices for crude and spot prices to value the products. It can be calculated from Table 1 that a narrowing of this spread by $1.39 or more would eliminate entirely the pre-tax cash flow, given the assumptions used for debt service. Presumably, contract prices for products would show less variation in spread from feedstocks also costed at contract rates. However, long-term predictions about the crude and crude product markets seem very hazardous; thus, this projection expresses profound ignorance about future market relationships.

Construction costs. It uses the $1,432.0 million figure contained in the Kutak Rock & Huie letter of December 11, 1979 (attached). Yet until the engineering cost estimate is obtained, this figure cannot be presumed to be very accurate. Moreover, cost overruns for large custom projects such as this are not unknown.

Assuming no tax-exempt financing is allowed does not do great damage to the projected cash flows; debt service increases only $10 million. However, should debt financing requirements exceed $1,779.3 million (total project costs of $2,128.0),

AGO 559858

pre-tax cash flow would fall to zero during the first 20 years. The possibility of foreign export financing mentioned at hearings would possibly decrease debt service costs.

Operating costs. Bonner and Moore estimated operating costs at $5.00 per barrel for the original Alpetco petrochemical facility. However, since Alpetco's latest product slate (Table 2) denotes a fuels refinery, operating costs were reduced to $2.00 per barrel. Bonner and Moore had estimated the operating costs for the 150,000 BPD Alaska Petroleum refinery at $1.06 per barrel.

At $2.00 per barrel of output, this would be total annual operating costs of $105 million. The Alpetco draft EIS estimates annual wage payments for operations at $18.6 million per year or 35¢ per barrel. Thus, $2.00 may be high depending on costs for maintenance, catalysts, and other items. If operating costs exceeded $3.39 per barrel, the $73.1 million annual pre-tax cash flow would be wiped out.

Other cost elements not included in the pro-forma cash flow that could be consisered part of the $2.00 operating charge are property taxes and field costs.

If the population impact on Valdez amounts to 2,124 persons as stated in Alpetco's EIS and Valdez continues to tax at the per capita maximums permitted by law, property taxes on Alpetco would come to $70.0 million or 12.7¢ per barrel.

If the Amerada-Hess case had been settled with Alpetco agreeing to pay the field costs, this would have been 47¢ per barrel of product or $24.6 million per year. The expected value of continued litigation should be around 31¢ per barrel or $16.4 million per year in field costs that Alpetco will be obligated to pay.

Tax Benefits and Rate of Return

Investment tax credits can only be carried forward seven years and may not exceed 50% of tax liability. Thus, they would be largely of no use to Alpetco given this pro-forma statement which has operating losses for the first five years. This may be one of the reasons why the project has been organized as a joint venture (a general partnership) so that the investment tax credits flow through to the partners who can use them, at least in the case of E.F. Hutton and Charter who by virtue of 100% ownership of their Alaska subsidiaries can consolidate the tax returns of partner and parent.

Thus, for computing the rate of return in one instance, the investment tax credit has been considered a reduction in the partners' capital investment.

As a partnership, the tax losses cannot be carried forward and applied to future joint-venture taxable income but must instead be flowed through to the partners in the year of the loss. Thus, depending on the partners' effective tax rate, there are additional tax benefits in the first years not reflected in the rate of return, if the partners have other income to shelter.

Finally, the rate of return does not consider any profits earned on the brokering or refining of royalty crude prior to refinery start-up.

While Alpetco will look to the rate of return on equity to evaluate its investment, potential bondholders will be looking to the operating income available to cover debt service and the amount of equity and value of assets as collateral in the event the project fails. The certainty of operating income for a facility that is to be project financed as this is becomes paramount since the parents' income and assets are not standing behind it. Without firm take or pay contracts from a creditworthy party, the operating income remains uncertain.

MB:vsw

Attachments

TABLE 1
ALPETCO
PRO FORMA OPERATING CASH FLOW
($ millions)

Year	(a) Operating Income	(b) Debt Service on Bonds	(c) Pre-Tax Cash Flow (a - b)	(d) Depreciation	(e) Payments to Principal	(f) Taxable Income (c-d+e)	(g) Income Tax (50% x f)	(h) Alaska Endowment Trust (5% x g)	After-Tax Cash Flow (c - g - h)
1983	235.1	162.0	73.1	179.0	19.4	(86.5)			73.1
1984	235.1	162.0	73.1	157.0	21.6	(62.3)			73.1
1985	235.1	162.0	73.1	137.0	24.1	(39.8)			73.1
1986	235.1	162.0	73.1	120.0	26.7	(20.2)			73.1
1987	235.1	162.0	73.1	105.0	29.8	(2.1)			73.1
1988	235.1	162.0	73.1	92.0	33.2	14.3	7.1		66.0
1989	235.1	162.0	73.1	80.0	36.9	30.0	15.0		58.1
1990	235.1	162.0	73.1	70.0	41.2	44.3	22.1		51.0
1991	235.1	162.0	73.1	62.0	45.9	57.0	28.5		44.6
1992	235.1	162.0	73.1	54.0	51.1	70.2	35.1		38.0
1993	235.1	162.0	73.1	47.0	57.0	83.1	41.6	2.1	29.4
1994	235.1	162.0	73.1	41.0	63.5	95.6	47.8	2.4	22.9
1995	235.1	162.0	73.1	36.0	70.8	107.9	53.9	2.7	16.5
1996	235.1	162.0	73.1	32.0	79.0	120.1	60.0	3.0	10.1
1997	235.1	162.0	73.1	28.0	88.2	133.3	66.7	3.3	3.1
1998	235.1	162.0	73.1	24.0	98.3	147.4	73.7	3.7	(4.3)
1999	235.1	162.0	73.1		109.8	182.9	91.4	4.6	(22.9)
2000	235.1	162.0	73.1		122.5	195.6	97.8	4.9	(29.6)
2001	235.1	162.0	73.1		136.7	209.8	104.9	5.2	(37.0)
2002	235.1	162.0	73.1		152.7	225.8	112.9	5.6	(45.4)
2003	235.1		235.1			235.1	117.6	5.9	111.6
2004	235.1		235.1			235.1	117.6	5.9	111.6
2005	235.1		235.1			235.1	117.6	5.9	111.6
TOTAL	5407.3	3240.0	2167.3	1264.0	1308.4	2211.7	1211.3	55.2	900.8

Internal Rate of Return (1) based on $348.7 million investment — 15.4%

(2) based on $205.5 million investment (net of 10% investment tax credit on $1432.0 million construction cost) — 32.2%

PREPARED BY:

LEGISLATIVE FINANCE DIV.
May 7, 1980

AGO 559861

FOOTNOTES TO TABLE 1

ALPETCO
PRO FORMA OPERATING CASH FLOW
($ millions)

NOTES: (a) 143,952 BPD of products @ $40.36 (from Table 2 of this memo) less $2.00 per barrel operating costs less $2.00 per barrel transport costs less 150,000 BPD of feedstock @ $30.60 per barrel (from Table 2 of April 26, 1980 memo "Alpetco Profits prior to Refinery Start-up"). The Bonner & Moore "Evaluation of Proposals for Royalty Oil Utilization" estimated the original Alpetco petrochemical facility's operating costs at $5.00 per barrel vs. $1.06 for the Alaska Petroleum 150,000 BPD fuels refinery. Phillips Petroleum reports tanker costs for February 1980 of $1.28 from Valdez to Los Angeles; the Alpetco sales contract with Charter Oil (Alaska) provides a further charge of 50¢ per barrel may be deducted from the sales price for unleaded gasoline and diesel.

(b) Assumes $450.0 million in tax-exempt bonds at 9% for 20 years plus $858.6 million in taxable bonds at 12% for 20 years, a total of $1308.6 million indebtedness as shown on attached Alpetco pro-forma construction funds flow statement from December 11, 1979 Kutak Rock & Huie letter. Tax-exempt bonds are reduced to $450 million based on Alpetco's oral testimony that this is the amount they are sure will qualify for tax-exempt status.

(d) Double declining balance method over 16 years as in the Bonner and Moore report for $1,432.0 million in construction cost as estimated on the Alpetco pro-forma statement.

AGO 559862

TABLE 2

ALPETCO

Value per Barrel of Output

Product Slate	Output BPD	Price $/B
Unleaded Gasoline	45,056	42.00
Jet Fuel	40,018	37.00
Diesel	33,396	33.50
Benzene	2,545	72.45
Toluene	5,635	56.70
Xylene	6,172	56.28
Naphtha	11,130	42.00
Total	143,952	
Weighted Average Price per Barrel		40.36

NOTES:

1. April 9, 1980 revised product slate of Alpetco; uses average percent of total products where a range of output is given.

2. Recent prices for Benzene, Toluene and Xylene from "Chemical Marketing Reporter"; other prices from "Platt's Oilgram Price Report."

PREPARED BY:

LEGISLATIVE FINANCE DIV.
May 7, 1980

Exhibit I

THE ALPETCO COMPANY

December 12, 1979

Pro Forma Funds Flow Statement
($Millions)

Source	1977 to 3rd Qtr, 1979	1979 4th Qtr.	1980 1st	1980 2nd	1980 3rd	1980 4th	1981 1st	1981 2nd	1981 3rd	1981 4th	1982 1st	1982 2nd	1982 3rd	1982 4th	Total
Equity:															
Charter Oil (Alaska), Inc.	-0-	5.0	6.0	60.2	13.5	-0-	12.1	13.4	14.6	13.0	14.5	13.2	6.4	73.4	244.2
Alaska Petrochemical Company	7.0	-0-	-0-	17.0	4.5	-0-	4.0	4.5	4.9	4.4	4.8	14.1	2.2	24.5	81.5
E.F. Hutton (Alaska), Inc.	-0-	-0-	-0-	4.8	1.3	-0-	1.2	1.2	1.4	1.2	1.4	1.2	.6	6.9	23.0
Total Equity	7.0	5.0	6.0	82.0	19.3	-0-	17.3	19.1	20.9	18.6	20.7	18.8	9.2	104.8	348.7
Debt:															
Supplier Credits-Takedown[1]	-0-	-0-	-0-	-0-	-0-	-0-	43.5	70.1	86.1	87.6	88.8	92.5	88.6	170.5	735.7
Tax Exempt Bonds-Gen[2]	-0-	-0-	-0-	-0-	-0-	-0-	60.2	75.4	76.9	78.6	92.0	89.0	92.8	-0-	572.9
Interim Financing-Takedown[3]	-0-	-0-	-0-	-0-	-0-	43.5	78.1	86.1	87.6	88.8	92.5	88.6	84.0	-0-	--
Interim Financing-Payback	-0-	-0-	-0-	-0-	-0-	-0-	(43.5)	(70.1)	(86.1)	(87.6)	(88.8)	(92.5)	(88.6)	(84.0)	--
Total Debt	-0-	-0-	-0-	-0-	-0-	43.5	146.3	161.5	164.5	167.4	184.6	177.5	176.8	86.5	1308.6
Total Sources	7.0	5.0	6.0	82.0	19.3	43.5	163.6	180.6	185.4	186.0	205.3	196.3	186.0	191.3	1657.3
Uses															
Development Cost	7.0	5.0	6.0	7.0	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	25.0
Construction Cost	-0-	-0-	-0-	75.0	10.3	39.1	154.4	160.2	171.1	166.1	177.8	163.0	149.1	149.1	1432.0
Interest Expense	-0-	-0-	-0-	-0-	-0-	2.6	3.5	6.0	7.5	12.1	13.5	18.0	21.9	26.3	111.4
Taxes & Insurance	-0-	-0-	-0-	-0-	1.0	1.0	2.0	2.7	3.1	4.0	4.5	5.0	5.5	6.5	35.4
Training & Misc.	-0-	-0-	-0-	-0-	-0-	.8	3.7	3.7	3.7	3.8	9.5	9.5	9.5	9.4	53.6
Total Uses	7.0	5.0	6.0	82.0	19.3	43.5	163.6	180.6	185.4	186.0	205.3	196.3	186.0	191.3	1657.3
Cumulative Totals	7.0	12.0	18.0	100.0	119.3	162.3	326.4	507.0	692.4	878.4	1083.7	1280.0	1466.0	1657.3	

[1] Takedown of supplier credits occurs on the first day of each quarter according to the amounts expended during the preceding quarter.

[2] Tax-exempt bonds are syndicated prior to December 18, 1980 and sold and drawn down in three equal amounts of $191.0 million each beginning January 1, 1981.

[3] Interim construction financing is used to bridge the takedown of supplier credits.

AGO 559864

Attachment to
Questions for Lekesche
5/8/80

Alpetco

December 18, 1979

Mr. Gordon Cain
Alpetco
3700 Buffalo Speedway
Suite 806
Houston, Texas 77098

Dear Mr. Cain:

On December 13, 1979 I received from you various letters, reports, contracts, and other documents relating to Article 10.2 (3)(a)-(c) and (f)-(h) and on December 13, 1979 I received from you additional information relating to Article 10.2(3)(d) and (e), the Joint Venture Agreement between Alaska Petrochemical Company, Charter Oil (Alaska), Inc. and E. F. Hutton (Alaska), Inc. and certain other information.

Under Article 10.2(3), the Agreement automatically terminates on December 19, 1979, unless Alpetco has satisfied all of the benchmark requirements or unless I grant Alpetco a six month extension as authorized under Article 10.2(3) of the Agreement. As of this date, December 18, 1979, I, my staff and advisors have not had sufficient time to review and analyze fully the information submitted by you. Thus, I have not determined whether or not I share your conclusion that you have satisfied the benchmark requirements. I shall be able to do so within the next thirty days and will advise you of my conclusions, in writing, not later than January 18 (hopefully sooner).

If I should conclude the information submitted does demonstrate satisfaction of the benchmark requirements then our Agreement remains in effect. If, on the other hand, I should conclude that you have not satisfied the benchmark requirements then I believe the contract would have terminated automatically on December 18, 1979. I am satisfied now that I would want to offer you the opportunity to satisfy the benchmark requirements by June 18, 1980, should I conclude you have not satisfied them by December 18, 1979. Accordingly, I hereby grant you the six month extension authorized under Article 10.2(3).

Jennie

In granting this extension I wish to make certain items clear. First, I offer no opinion or judgment at this time concerning Alpetco's compliance or non-compliance with Article 10.2(3). The provision is complex and more time is needed to review the information submitted by Alpetco. I see no benefit either to Alpetco or to the State by offering a preliminary opinion based on partial analysis, since such preliminary judgment would not provide either of us with the firm representations needed to proceed. Second, I recognize and appreciate that Alpetco's position is that it has complied with Article 10.2(3) and an extension is neither necessary nor requested by Alpetco. Nevertheless, I am granting the extension because I do not wish to preclude the opportunity of allowing you additional time to comply in the event I cannot concur with you. Without this action of granting you the extension I believe that on January 18, should I conclude you have not complied, the Agreement would be terminated. By granting this extension you will have the opportunity but, not the obligation to take additional steps, of course, to satisfy Article 10.2(3).

Sincerely,

Robert E. LeResche
Commissioner

REL:blg

OFFICE OF THE GOVERNOR
JUNEAU

JAY S. HAMMOND
GOVERNOR

FOR INFORMATION CONTACT:
Office of the Governor
Pouch A Juneau, Alaska 99811
OR PHONE: 907-465-3500
Gladys Reckley
Press Secretary

HAMMOND GIVES APPROVAL FOR ALPETCO PROJECT
DECEMBER 27, 1979
#276

FOR IMMEDIATE RELEASE

JUNEAU--Gov. Jay Hammond today said he is advised that the Alpetco Company has satisfied all terms of the initial part of its contract for state royalty oil.

Hammond's approval of Alpetco's critical 18-month benchmark clears the way for the company to proceed with construction of its $1.5 billion dollar petrochemical refinery complex in Valdez.

The governor said, "this 18-month benchmark was an important key to the contract. " During that period Alpetco secured commitments for its financing from the City of Valdez and from large corporations; it contracted to sell 70 percent of the facility's products; secured commitments for interim financing; filed a complete Environmental Impact Statement; filed all material state, local and federal permit applications; completed plant design and optimization necessary to obtain a definitive project cost estimate; delineated a product slate; and spent $10 million as required by the contract.

-more-

AGO 559867

Hammond said, "the status of Alpetco's progress to date has reinforced my view that Alaska need not subsidize new industry, but can require that it be self-sustaining and environmentally sound.

"These policies will insure that healthy growth occurs in our state, and Alpetco has come a long way toward this objective," Hammond added. The governor noted also that the state contract was written to insure that the construction phase of the Alpetco project is carried out with diligence.

-30-

February 8, 1980

The Alpetco Company
3700 Buffalo Speedway
Suite 806
Houston, Texas 77098

Re: Agreement for the Sale and Purchase of State Royalty Oil Between Alaska Petrochemical Company and the State of Alaska dated February 22, 1980, as amended by Amendment dated May 17, 1978.

Gentlemen:

After thoroughly reviewing the documents submitted by you on or before December 18, 1979, I am of the opinion that the Alpetco Company, as the duly approved assignee of all of the rights of Alaska Petrochemical Company under the captioned Agreement (the "Agreement"), has timely fulfilled all the requirements set forth in Article 10.2(3)(a-h) of the Agreement, and that the Agreement is in full force and effect at the date hereof.

Sincerely,

Robert E. LeResche

Robert E. LeResche
Commissioner

AGO 559869

Lonnie

STATE OF ALASKA

JAY S. HAMMOND, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER / POUCH M — JUNEAU 99811

April 28, 1980

Mr. Dudley K. Parker
General Manager
The Alpetco Company
3400 Buffalo Speedway
Houston, Texas 77098

Dear Mr. Parker:

Since my letters of December 18, 1980, extending the period of compliance for your 18 month benchmark under Article 10.2(3) (a-h), and of February 8, 1980, wherein I stated my opinion that you had complied with that benchmark based upon your submissions of that date, several things have come to my attention. These new pieces of information have led me to consider again whether compliance has in fact occurred under present circumstances.

First, the Alaska Pipeline Commission filed Docket No. P-80-2, Order No. 1 on March 10, 1980, ordering Alpetco to show cause and secure a permit for your crude and product pipelines. The Commission noted that it has received no application for the pipelines under AS 42.06.240. Article 10.2(3)(g) requires that you "complete and file all material state, local and federal permit applications" within the benchmark time period.

Second, on April 9, 1980, you submitted a letter to me describing a design change in your facility. I will have to have this design change evaluated in detail to determine whether your previous apparent compliance with Article 10.2(3)(h) has changed, and whether the newly-described facility meets the requirements of Article 4.2.1.

Third, it is important that I determine whether you have proceeded "with reasonable diligence" as required in Article 4.2.1 since December toward meeting the 24 and more importantly the 30-month benchmark requirements. In this regard, I

AGO 559870

10-J9LH

request that you submit to me a more thorough description of your progress in preparing the definition financing documents as required by Article 10.2(5), including drafts, and of your progress toward contracts for actual construction work at Valdez including any contracts, as required by the same article.

As you know timely financing and construction of the petrochemical facility promised is absolutely essential if our contract is to remain in force. Further substantiation that such is in fact occurring is necessary at this time.

Sincerely,

Robert E. LeResche

Robert E. LeResche
Commissioner

LAZARD FRÈRES & CO.
ONE ROCKEFELLER PLAZA
NEW YORK, N.Y. 10020

CABLE ADDRESS "LAZARD NEW YORK"
TELEPHONE (212) 489-6600

NEW YORK

March 20, 1980

Dr. Robert E. LeResche
Commissioner
Department of Natural Resources
State of Alaska
Pouch "M"
Juneau, Alaska

Dear Commissioner LeResche:

You have asked me to write down the salient points of my several discussions with you of last December regarding the Alpetco project, and specifically how we viewed the documentation and representations made to you by Alpetco, E. F. Hutton Group and Thyssen Rheinstahl Technik in light of the benchmark requirement outlined in Article 10.2(3)(d) of the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978.

At that time we reviewed letters dated December 7, 1979 and December 18, 1979 from Thyssen Rheinstahl Technik to The Alpetco Company, letters dated November 19, 1979 and December 21, 1979 from The E. F. Hutton Group to The Honorable Bill Walker, Mayor, City of Valdez, and letters dated December 13, 1979 to The Alpetco Company from Charter Oil (Alaska), Inc., The Charter Company, Alaska Petrochemical Company, Alaska Interstate Company, Seatrain Lines, Inc., E. F. Hutton (Alaska), Inc. and E. F. Hutton Group, Inc.

It was our opinion at that time that the letters referred to above, taken as a whole, could be considered to be a reasonable financial commitment under the special circumstances of this project.

The special circumstances to which we referred were (a) the size of the project, (b) the additional engineering work which would have to be completed prior to irrevocable commitments from long term lenders, and (c) that major construction on the project itself would not commence for one year.

In addition, we took into consideration

-- the financial strength and reputation of Thyssen, as well as the experience and reputation of the E. F. Hutton Group, Inc.

-- statements by the Chairman of the Thyssen Board, Dr. Gshwend, in Seattle on December 13, 1979, attesting

AGO 559872

to the assumption by Thyssen of responsibility to complete the financing package;

-- statements made by representatives of the sponsors and senior officials of Thyssen that engineering studies which will require an estimated $25 million to complete have been commenced;

-- acceptance of the requirement that the sponsors must spend $100 million before the State will deliver any royalty oil.

We offered no opinion as to whether or not the statements of Thyssen, the sponsors and the E. F. Hutton Group constitute a binding legal commitment. We did understand that you had discussions with counsel on this matter. From the point of view of a member of the financial community, however, we believed that these oral and written statements were, in a practical sense, as firm as could realistically have been anticipated at the time.

Very truly yours,

Peter A. Lewis

PAL:g

THE ALPETCO COMPANY
3700 BUFFALO SPEEDWAY
HOUSTON, TEXAS 77098
TELEPHONE 713 840-1243 TELEX 791461

December 17, 1979

Dr. Robert E. LeResche
Commissioner
Department of Natural Resources
State of Alaska
Pouch "M"
Juneau, Alaska 99811

Re: Article 10.2(3) of the Agreement for the Sale and Purchase of State Royalty Oil between Alaska Petrochemical Company and the State of Alaska dated February 22, 1979 (the "Agreement")

Dear Commissioner LeResche:

During our meeting last Thursday, December 13, in Seattle, you and your associates raised certain questions concerning the material submitted to you at that meeting and we are herewith conveying material which we believe will clarify the points raised, all of which had to do with paragraph 10.2(3)(d) and (e) of the Royalty Oil Contract.

These points were as follows:

1. Two questions were raised regarding Thyssen's financing contract: one was the suggestion that the language of paragraph 3 of Thyssen's December 7, 1979 commitment letter be clarified [10.2(3)(d)]. The other question was whether or not Thyssen would agree to provide a commitment for interim financing for the construction of the Facility [10.2(3)(e)].

   Included herewith is Thyssen's telex which clarifies the language in question and which commits to provide interim construction financing, if and when needed.

2. A question was raised by Don Holman, Esq. of Preston, Thorgrimson, Ellis and Holman as to whether or not the City of Valdez could issue industrial revenue bonds in connection with Alpetco's financing without violating AS 37.10.085.

   Enclosed herewith are two legal opinions, one dated December 13, 1979 from Wohlfarth and Flint (with enclosures), bond counsel for the City of Valdez, and an opinion dated December 14, 1979 from Kutak, Rock & Huie, bond counsel for EF Hutton & Company Inc.

3. A question was raised under paragraph 3 of the May 17, 1978 amendment to the Royalty Oil Agreement as to whether or not Alaska Interstate would be willing to commit for all of Alaska Petrochemical's share of the $100 million commitment required under the amendment.

AGO 559874

601 WEST 5TH AVENUE, ANCHORAGE, ALASKA, 99501, TELEPHONE 907 272-1517, TELEX 090-251157

Alaska Interstate Company's answer was affirmative and transmitted herewith is a letter dated December 14, 1979 whereby Alaska Interstate Company commits to fulfill all of Alaska Petrochemical Company's portion of the $100 million commitment, if necessary.

4. Also transmitted herewith is Alaska Petrochemical Company's Progress Report No. 18 dated December 18, 1979.

The above material along with that transmitted to you at our December 5, 1979 meeting in Juneau and our December 13, 1979 meeting in Seattle, together with the testimony given at those meetings, in our opinion successfully complies with all of the December 18, 1979 "Benchmarks" on the Royalty Oil Agreement.

Sincerely,

Gordon A Cain

Gordon A. Cain
President

GAC:t
Enclosures.

Rec'd 12-17-79
10 25 am

RCA DEC 17 1106+
ALPETCO HOU

8588561Z TRT D 17.12.79 FS NR. 45276 SCHWARZE/WK 17.10

ATTENTION: MR. CHARLES HONIG OR MR. GORDON CAIN

PLEASE FIND HEREIN BELOW OUR REVISED WORDING FOR COMMITMENT LETTER:

GENTLEMEN:

IN CONSIDERATION OF ALPETCO ENTERING INTO THE ATTACHED ENGINEERING- AND CONSTRUCTION-CONTRACT WITH THYSSEN RHEINSTAHL TECHNIK GMBH (THYSSEN) AND FOSTER WHEELER ENERGY CORPORATION FOR THE ENGINEERING, SUPPLIES, AND CONSTRUCTION OF THE FACILITIES OF ALPETCO'S VALDEZ, ALASKA REFINERY AND PETROCHEMICAL FACILITY (PROJECT), SUCH PROJECT HEADED BY THE ALPETCO COMPANY (ALPETCO) - A JOINT VENTURE PARTNERSHIP OWNED BY CHARTER OIL (ALASKA), INC., A SUBSIDIARY OF THE CHARTER COMPANY, ALASKA PETROCHEMICAL COMPANY AND E.F. HUTTON (ALASKA) INC. - WE HEREBY COMMIT TO ARRANGE FINANCING OF UP TO US-DOLLAR 750,000 000,-- (SEVENHUNDREDANDFIFTY MILLION US-DOLLARS) TO COVER COSTS FOR THE ENGINEERING, EQUIPMENT, MATERIALS, CONSTRUCTION AND OTHER SERVICES REQUIRED FOR THE PROJECT.

IN ADDITION TO ARRANGING THE ABOVE FINANCING, WE HEREBY ALSO COMMIT TO ARRANGE INTERIM FINANCING FOR THE CONSTRUCTION OF THE PROJECT OF UP TO US DOLLAR 150,000,000 (ONEHUNDREDANDFIFTY MILLION US-DOLLARS) IF AND AS NEEDED, PROVIDED THE EXISTING BANK COMMITMENTS DO NOT MATERIALIZE.

OUR COMMITMENTS HEREUNDER ARE SJUBJECT TO THE FOLLOWING:

1. ALPETCO'S ACQUIRING AND CONTRIBUTING TO THE PROJECT FINANCING OF AT LEAST US DOLLAR 750,000,000,-- (SEVENHUNDREDANDFIFTY MILLION US-DOLLARS) BY A COMBINATION OF THE ISSUANCE OF INDUSTRIAL REVENUE BONDS, EQUITY INVESTMENT AND/OR SATISFACTORY FORMS OF FINANCING BY ALPETCO'S PARTNERS AS ARE REQUIRED FOR THE PROJECT IMPLEMENTATION,
AND

2. ALPETCO'S OBTAINING ALL NECESSARY APPROVALS AND PERMITS REQUIRED BY THE RESPONSIBLE AUTHORITIES FOR THE CONSTRUCTION AND OPERATION OF THE PROJECT, THE ROYALTY CRUDE OIL CONTRACT BEING IN EFFECT AND ALPETCO HAVING THE RIGHT TO TAKE CRUDE OIL NOT LATER THAN JULY 18, 1980, AND

3. EXECUTION OF DEFINITIVE DOCUMENTS RELATING TO THE LONG-TERM FINANCING FOR THE PROJECT ON OR BEFORE DECEMBER 18, 1980.

IF THE ABOVE DEFINITIVE AGREEMENTS ARE NOT ENTERED INTO BY SUCH DATE, WE RESERVE THE RIGHT TO TERMINATE OUR COMMITMENT HEREUNDER WITHOUT ANY LIABILITY ON OUR PART.

THIS LETTER REPLACES OUR DECEMBER 7, 1979 LETTER TO YOU ON THE SAME SUBJECT, A COPY OF WHICH IS ATTACHED HERETO.

YOURS FAITHFULLY,
W. SCHWARZE / THYSSEN RHEINSTAHL TECHNIK GMBH

ALPETCO HOU

8566561Z TRT D

western union

THYSSEN

Thyssen Rheinstahl Technik GmbH · Postfach 80 23 · 4000 Düsseldorf 1

THYSSEN RHEINSTAHL TECHNIK GMBH

The Alpetco Company
3700 Buffalo Speedway
Houston, Texas 77098
U. S. A.

=

Thyssen Technik-Haus
Königsallee 106
Düsseldorf

Ihre Zeichen	Ihre Nachricht vom	Unsere Zeichen	Unser Hausruf (Direktwahl) (02 11) 38 03-	Düsseldorf
		Recht/Dr.W./ho		December 7, 1979

Betreff

Gentlemen:

In consideration of Alpetco entering into the attached Engineering- and Construction-Contract with Thyssen Rheinstahl Technik GmbH (Thyssen), or a Joint Venture consisting of Thyssen and another party nominated by Thyssen, for the engineering, supplies and construction of the facilities of Alpetco's Valdez, Alaska Refinery and Petrochemical Facility (Project), such Project headed by The Alpetco Company (Alpetco) - a Joint Venture partnership owned by Charter Oil (Alaska), Inc., a subsidiary of The Charter Company, Alaska Petrochemical Company and E.F. Hutton (Alaska), Inc. - we hereby commit to arrange financing of up to US$ 750,000,000.-- (sevenhundredandfifty million US-Dollars) to cover cost for the engineering, equipment, materials, construction and other services required for the Project.

Our commitment hereunder is subject to Alpetco's acquiring and contributing to the Project financing of at least US$ 750,000,000.- (sevenhundredandfifty million US-Dollars) by the issuance of industrial revenue bonds, equity investment and other satisfactory forms of financing by Alpetco's partners as are required for the Project implementation.

AGO 559878

Geschäftsführung: Dr. Helmut Gschwend (Vorsitzender)

Handelsregister-Nr.: HRB 3311

Definitive agreements for all the financing required shall be entered into by December 18, 1980, on such terms and conditions as are customarily required for similar financings by lenders at such time. If such definitive agreements are not entered into by such date, we reserve the right to terminate our commitment hereunder without any liability on our part.

The financing shall be subject to Alpetco obtaining all necessary approvals and permits required by the responsible authorities for the construction and operation of the Project, the Royalty Crude Oil Contract being in effect and Alpetco having the right to take crude oil not later than July 18, 1980.

Yours faithfully,

THYSSEN RHEINSTAHL TECHNIK
G.m.b.H.

AGO 559879

December 13, 1979

Mr. Mark Lewis, Manager
City of Valdez
P. O. Box 307
Valdez, Alaska 99686

Dear Mr. Lewis:

A question has apparently been raised as to whether the proposed industrial revenue bond financing by the City of Valdez for Alpetco violates AS 37.10.085 which prohibits either the state or political subdivision to lend its credit for the use of a private corporation or to borrow money for the use of a private corporation.

In our opinion, the answer to the above question is clearly no. We point out to you at the outset that the entire City of Valdez Marine Terminal Revenue Bond program was effectuated under the same provisions of the City Charter and in light of AS 37.10 .085. This financing was accomplished after extensive legal research. The principal case cited in the legal research was Wright v. City of Palmer, 468 P.2d 326 (Alaska, 1970) where the court deals with the precise issue on page 328 and 329. The court there held that a general obligation bond issue of the City of Palmer to purchase an industrial plant site for a specific private corporation did not violate AS 37.10.085 and was consistent with specific provisions of the Alaska Constitution.

For the benefit of Don Holman, Esq. of Preston, Thorgrimson, Ellis & Holman who has apparently raised the question, we are enclosing a copy of our memorandum of law on this subject matter and a copy of the case of Wright v. City of Palmer.

If you have any other questions with respect to this matter, please do not hesitate to call on us. Because the matter is urgent, we are telecopying this opinion directly to you and will mail to Mr. Holman a copy with a copy of the above-referenced enclosures.

Very truly yours,

WOHLFORTH & FLINT

By
Eric E. Wohlforth

EEW/lw

AGO 559880

cc: Don Holman, Esq.

April 4, 1977

Exxon Company, U.S.A.
P. O. Box 397
Houston, Texas 77001

Attention: Andrew W. Hero, Esq.

Sirs:

You have asked our opinion as to the authority of the City of Valdez, Alaska, to issue Marine Terminal Revenue Bonds without specific state statutory authorization. It is our opinion that the City has this power as a home rule city of the State of Alaska. Further, in our view, this power was validly exercised consistent with the Alaska State Constitution by the City in the proceedings pursuant to which $265,000,000 City of Valdez, Alaska, Marine Terminal Revenue Bonds (ARCO Pipe Line Company Project) Series 1977 were issued on February 15, 1977. We set forth our reasoning and legal analysis below.

Home Rule Question

Sections 1 through 8 of Article X of the Alaska Constitution establish the structure of local government in the State of Alaska. Sections 9, 10 and 11 of Article X of the Constitution provide the basis for home rule municipalities in the State of Alaska. Section 9 of Article X states:

> "The qualified voters of any borough of the first class or city of the first class may adopt, amend, or repeal a home rule charter in a manner provided by law. In the absence of such legislation, the governing body of a borough or city of the first class shall provide the procedure for the preparation and adoption or rejection of the charter. All charters, or parts or amendments of charters, shall be submitted to the qualified voters of the borough or city, and shall become effective if approved by a majority of those who vote on the specific question.

AGO 559881

Section 10 of Article X states:

> "The legislature may extend home rule to other boroughs and cities."

And Section 11 of Article X states:

> "A home rule borough or city may exercise all legislative powers not prohibited by law or by charter."

These constitutional provisions are further expanded by statute. Section 29.08.010 of the Alaska Statutes Annotated provides that:

> "A home rule municipality is a municipal corporation and political subdivision and is a borough of the first class or city of the first class which has adopted a home rule charter. It has all legislative powers not prohibited by law or by charter."

Article 1 of Chapter 13 of Title 29 provides for the adoption and amendment of charters for home rule municipalities. Article 2 of Chapter 13 of Title 29 places certain limitations on home rule municipalities.

We have, of course, concluded that the City of Valdez Charter was validly adopted and that its amendments have been validly adopted. We refer you specifically to the Charter Amendment adopted in connection with the issuance of Industrial Development Bonds attached hereto as Appendix A.

The Supreme Court of Alaska in Jefferson v. State, 527 P.2d 37 (Alaska 1974) set down the limits of home rule power of Alaska charter cities. In Jefferson v. State the court reviewed the earlier four cases analyzing the home rule provision of the State Constitution (Article X, §11) as well as the two Law Review articles which had analyzed and critized the court's earlier opinions. In Jefferson v. State, the court held that Article X, §11, which states that:

> "A home rule borough or city may exercise all legislative powers not prohibited by law or charter."

meant what it says, namely that there must be a prohibition on the exercise of municipal power arising from the law or charter for a power to be denied to home rule municipalities.

At 527 P.2d, page 43, the court stated that:

> "The test we derived from Alaska's Constitutional provisions is one of prohibition, rather than traditional tests such as statewide versus local concern. A municipal ordinance is not necessarily invalid in Alaska because it is inconsistent or in conflict with the State statute. The question rests on whether the exercise of authority has been prohibited to municipalities. The prohibition must be either by express terms or by implication such as where the statute and ordinance are so substantially irreconcilable that one cannot be given its substantive effect if the other is to be accorded the weight of law."

The case is important because the court in earlier opinions, principally Chugach Electric Association v. City of Anchorage, 476 P.2d 115 (Alaska 1970) and Macauley v. Hildebrand, 491 P.2d 120 (Alaska 1971), had indicated its preference for the test of the so-called "local activities rule". As stated in the concurring opinion in Jefferson v. State, which advocated the adoption of the "local activities rule", this rule requires the court to focus upon whether the particular subject under consideration is of such statewide concern that the exercise of municipal power is inconsistent with the effectuation of statewide policy, as expressed by statute. The court's adherence to this test in the two other recent cases prior to Jefferson v. State had been extensively critized in Sharp, Home Rule in Alaska: A Clash Between the Constitution and the Court, 3 UCLA-Alaska L.R. 1 (1973). The author of the Law Review article stated at page 53

> "In the ten years that followed statehood the court refrained from seeking guidance from other states in that interpretation of its home rule grant, and in the Lien, Maier and Rubey decisions displayed an understanding of the intent of the constitutional provision. These three decisions set a pattern of broad, constitutionally based home rule powers and of a liberal judicial construction of home rule powers. However, in Chugach, a case which followed a substantial change in court personnel, the court reversed both patterns. It adopted the state-local test, which it denominated the 'local activities rule', with the result that where any statewide interest is at stake a state statute which is inconsistent with an ordinance of a home rule municipality will constitute a prohibition."

In Jefferson v. State, however, the court stated that the framers of the Constitution

> " . . . were aware of the difficulties encountered in other jurisdictions where delegations of power to local units were conferred in terms, such as 'matters of local concern' or of local affairs which were intended to create an exclusive sphere of municipal action free from any intrusion by the state legislature." (527 P.2d 37, 43)

The court stated that attempts by the courts of those jurisdictions to resolve conflicts had led to confusion and inconsistencies and, in view of this, that the constitutional delegates undertook to give Alaska home rule municipalities a wide range of powers to meet the differing needs of the widely scattered communities within the state. They hoped that the Article X, §11 grant of home rule authority would lead the courts to take a new approach to the subject of conflicts between municipalities and the state.

The court in Jefferson v. State returned to the legal rationale adopted in Rubey v. City of Fairbanks, 456 P.2d 470, 475 (Alaska 1969) stating it declined to follow California's pre-emption-by-state-occupation-of-the-field-doctrine because of the difference between California's and Alaska's home rule provisions. The court stated that the foundation for the "new approach" resolving conflicts between municipalities and the state had been laid in past decisions of the Alaska Supreme Court which favored the exercise of legislative powers by local government units. For the last statement, the court cited Lien v. City of Ketchikan, 383 P.2d 721-723 (Alaska 1963); City of Juneau v. Hixson, 373 P.2d 743 (Alaska 1962); Rubey v. City of Fairbanks, 456 P.2d 470-475 (Alaska 1969).

In Jefferson v. State the court clearly reverted to the rationale of the Rubey case citing it three times in rejecting the test of the "local activities rule". In stating that the "prohibition test" is the one upon the Alaska Supreme Court will decide cases it stated at footnote 33 as follows:

> "We affirm our rejection of the doctrine of state pre-emption by 'occupying the field'. We will not read into a scheme of statutory provisions any intention to prohibit the exercise of home rule authority in the area of the law. If the legislature wishes to 'pre-empt' an entire field, they must so state. See Rubey v. City of Fairbanks, 456 P.2d 470 (Alaska 1969).
>
> We note that the legislature has done this in its new Title 29, Municipal Code. AS 29.13.100 provides in part:
>
> 'Only the following provisions of this title apply to home rule municipalities as prohibited on acting otherwise than as provided.'"

The significance of Jefferson v. State becomes clear when the UCLA-Alaska Law Review article is read. The author of the article stated that the Chugach case was a

radical deviation and a reversal from the line of home rule decisions that preceded it. Jefferson v. State on the other hand shows that the Supreme Court was aware of its error in adopting the local activities rule. The opinion stands as a guide to home rule cities that they may legislate in all areas not prohibited by law or charter.

It may be argued that in some cases application of the "prohibition" instead of the "local activities" test is not of major importance since the results tend to be the same. Certainly in Jefferson v. State the court held that the Anchorage Charter provision against sale of public utilities except by three-fifths vote fell in light of the general law provision that the area wide sewer power could no longer be exercised in the City once it had been properly assumed by the Borough. In the next case of conflict between state law and municipal home rule ordinance, Adkins v. Lester, 530 P.2d 11 (Alaska 1974), the court held that a Fairbanks city ordinance to the extent that it was in conflict with state traffic regulations constituted an exercise of home rule power expressly prohibited by the legislature. The court cited with approval on its previous statement in Jefferson v. State, at 527 P.2d 43 namely that the question of validity of municipal ordinances rests whether the exercise of the authority has been prohibited to municipalities.

The significance, however, of the adoption of the "prohibition" test in the instant situation, as opposed to the "local activities" test, lies in the fact that the provisions of the home rule charter of the City of Valdez and state law need alone be addressed in determining whether or not the City can issue bonds for marine terminal purposes. The court in deciding whether or not this power may be exercised need not consider whether the borrowing by the City for this purpose is a matter of statewide concern. Such an examination would be required under the local activities test.

The court was assisted in Jefferson v. State by the legislative expression in AS 29.13.100 which provides in part:

> "Only the following provisions of this title apply to home rule municipalities as prohibitions on acting otherwise than as provided."

At footnote 33, at 527 P.2d page 43 the court stated that: "If the legislature wishes to pre-empt the entire field, they must so state."

In Roderick v. Sullivan, 528 P.2d 450 (Alaska 1974) at page 455, the court noted that AS 29.13.100 constituted a specific provision that state law on reapportionment (AS 29.23.020) prohibited future home rule enactments which provide otherwise, quoting with approval Jefferson v. State. The court again quoted Jefferson v. State in Adkins v. Lester, 530 P.2d 11 at page 15 in determining that the legislature had expressly prohibited a home rule city from enacting an ordinance in conflict with state regulations in regard to the use and operation of motor vehicles.

The holding of the Jefferson v. State affirms the uniqueness of the Alaska Constitutional home rule provision and makes inapplicable most of the law review articles and cases in other states dealing with the scope of home rule.

As noted in the footnote 26 at Jefferson v. State, 527 P.2d 42, Alaska's home rule provision is a "sword" not a "shield". It does not carve out any area where the state may not act by requiring a court determination of whether the exercise of a municipal power is statewide or local in nature. The court does not have to make such a determination because it must only determine whether the exercise of power is prohibited to municipalities. In discussing the Alaska home rule constitutional provision at 48 Minnesota Law Review 643, 686 The Limits of Municipal Power Under Home Rule: A Role for the Courts, Terrance Sandalow, it is stated that it grants broader power than is granted in any other state constitution.

The court's interpretation of the home rule provision in Article X, §11 of the State Constitution is consistent with §1 of Article X, the introductory section to the Article on Local Government in the Alaska Constitution, which reads:

> "The purpose of this article is to provide for a maximum local self government with a minimum of local government units, and prevent duplication of tax-levying jurisdiction. A liberal construction shall be given to the powers of local government units."

The most recent dealing with Article X, §11 of the Alaska Constitution is Area Dispatch, Inc. v. City of Anchorage, 544 P.2d 1024 (Alaska 1976). The court found no prohibition in State law on the City establishing a lessor percentage of signatures necessary for referendum vote than fixed in State law. It instead found that the Charter itself fixed the limitation by reference to State law. Before holding on the point the court stated:

> "Article X, §11, of the Alaska Constitution provides that home rule cities 'may exercise all legislative power not prohibited by law or charter'. Numerous court opinions and commentators have explained that a municipal ordinance of a home rule municipality is not invalid because it is inconsistent or in conflict with a state statute. The question of validity of the conflicting ordinance rests on whether the exercise of the authority has been prohibited to home rule municipalities. 'The prohibition must be either by express terms or by implication such as where the statute and ordinance are so substantially irreconcilable that one cannot be given its substantive effect if the other is to be accorded the weight of law.'"

It cannot be said, in our view, that the State legislation permitting industrial development bond financing through the Alaska Industrial Development Authority (AS 44.61) constitutes an implied prohibition on the City of Valdez undertaking such a financing. This statute and Ordinance No. 7525 of the City are in no degree "irreconcilable". Further, port financings have as a factual matter been undertaken by Alaska cities such as Anchorage for many years even though the freight activity is by no means limited to that city.

Public Purpose Question

Article IX, Section 6 of the Alaska Constitution provides that

> "No tax shall be levied, or appropriation of public money made, or public property transferred, nor shall the public credit be used, except for a public purpose."

The leading and original case on revenue bond financing in Alaska is DeArmond v. Alaska State Development Corporation, 376 P.2d 717 (Alaska 1962). The Corporation's function was to provide mortgage money for development loans within the State. The court held that the issuance of revenue bonds or debentures secured only by revenues of the Corporation to raise money for this purpose did not violate Article IX, Section 6 for two reasons. First, it found that the Corporation did serve a public purpose and in so finding it held that a State loan of $150,000 to the Corporation was valid. Secondly, it found that since the Corporation's bonds are payable only from revenues of the Corporation, and that the State was not indebted or obligated meant that the transaction did not violate Article IX, Section 6. The court stated at page 722 as follows:

> "No public funds are being transferred to the corporation other than the loans just mentioned. Funds realized from the sale of certificates will come from private sources. The credit of the State is not being pledged. Even though we have found that the corporation's activities will serve a public purpose, it is clear enough that its objectives must be accomplished without the use of public funds and State credit. No violation of the Constitution has been shown."

In Walker v. Alaska State Mortgage Association, 416 P.2d 245 (Alaska 1966), the court followed its holding in the DeArmond case in finding that activities of the Association in the selling of bonds to provide funds to make mortgage loans constituted a public purpose. The court held that the authority to issue bonds did not violate Article IX, Section 8 of the Constitution which requires that State debts be authorized for capital improvements and ratified by the voters. The court stated that

> "In DeArmond, we concluded that the funds realized through the sale of bonds backed only by the resources and credit of the corporation and which did not constitute debts of the State were not public funds. We are of the opinion that our holding in DeArmond is controlling here and conclude that bonds, notes and debentures of the association are not debts of the State of Alaska within the scope of Article IX, Section 8 of our Constitution."

Two things should be noted about these above two cited cases. First, the court found that the funds derived from the sale of revenue bonds are not public funds and in two cases holds that this is an independent ground for the transaction not to be prohibited by Article IX, Section 6. Secondly, in the Walker case the court has direct occasion to consider whether or not the restriction that State debt must be issued for capital improvements applies to revenue bonds issued by a corporation of the State and never even considers the point but holds nevertheless that the revenue bonds should not be characterized as State debt under Article IX, Section 8.

The other major Alaska case considering the above question is Wright v. City of Palmer, 468 P.2d 326 (Alaska 1970). The court there considered whether or not the authorization by the City of Palmer of general obligation bonds to provide funds to construct a manufacturing plant for lease to private enterprise violated the lending of credit provision of AS 37.10.085 which prohibits either the State or a political subdivision from lending its credit for the use of a private corporation, or borrowing money for the use of a private corporation. The court also considered whether the transaction violated Article IX, Section 6 of the Alaska Constitution. The court concluded that the question of whether the public credit is being pledged for private purposes was also comprehended under the broader question of whether a public purpose was served by the bond issue and plans for its expenditure. In holding that the plan did constitute a public purpose it cited DeArmond and Walker. The second ground of Walker and DeArmond, namely, that since the bonds were revenue bonds, payable only from project

revenues, there was no violation of Article IX, Section 6, was obviously not available to the court. The court stated however, in footnote four on page 329 that

> "The courts which have upheld bonding projects as a legitimate exercise of power by the political subdivisions have held that a statute which pledges only project revenues does not pledge the public credit, and, therefore does not lend the public credit in aid of anyone." (citing cases)

There are several additional features of Wright v. City of Palmer, which are relevant to the instant situation. In the first place it should be noted that unlike the situation in DeArmond and Walker there was no specific authority in State statutes for the transaction. That is to say the Legislature had not directly spoken on the subject matter nor had it made legislative findings that a public purpose would be served by authorizing the issuance of local government bonds for manufacturing or industrial plants. The fact that the Legislature had spoken in other contexts on the desirability of public assistance to induce new industries was briefed and noted by the court in its reference to the power of the City Council to lease property to industries. In any event, the important fact is that the court considered the action of the City Council of Palmer to have equal dignity with State legislative action on the subject matter. It stated that

> "The role of the courts in matters of this kind is relatively limited. Our function is not to determine whether, as prudent burghers, we might think this plan wise . . ."
>
> "If the city fathers and the voters of the community feel that this plan of action is necessary, it is not for us to retard them. It is within their legislative province to determine whether the advantages outweigh the risks."

The limits which Justice Connor set on the scope of the court's function in deciding these matters is of importance in determining the rationale of the decision. The court states at page 331

> "If the plan of action were plainly foolhardy, or if amounted to the pledging of credit or giving away of assets without any corresponding discernible benefit, we might be persuaded to strike down the plan."

There is nothing in this judicial expression of the court's role in determining cases of this nature which indicates that a plan of action would be found unconstitutional if indeed it could be proven that a particular industry would have located within municipal boundaries regardless of the availability of public financing. Although the case seems to assume that the availability of public financing was an inducement to location there is nothing in the record that the fact of location without the public financing would cause the court to strike the plan down. The court did state the perameters of judicial scrutiny, namely, that the plan must be plainly foolhardy or amount to the pledging of credit or the giving away of assets without any corresponding discernible benefit in order for it to be striken. There is nothing in our view, in the instant situation which can be characterized under this terminology and indeed, assisting in the financing of the pipeline has obvious direct and ancillary public purpose benefits both to the State of Alaska and to the City.

If you require further analysis of the above points, please call on us.

Very truly yours,

WOHLFORTH & FLINT

By_____
Eric E. Wohlforth

EEW:jr

Neal WRIGHT, Appellant,

v.

CITY OF PALMER, Municipal Corporation, State of Alaska, Theodore Schmidtke, Mayor, Emilie St. Pierre, City Clerk, and Members of the City Council of the City of Palmer, Appellees.

No. 1192.

Supreme Court of Alaska.
April 27, 1970.

Declaratory judgment action to invalidate city's issuance of general obligation bonds. The Superior Court, Third Judicial District, C. J. Occhipinti, J., granted judgment, and appeal was taken. The Supreme Court, Connor, J., held that issuance of general obligation bonds to finance a 20-year improvement program providing for purchase of a site and construction of a manufacturing and processing facility which would be leased to a private corporation did not, under circumstances presented constitute an unlawful lending of credit to a private corporation and did not constitute a violation of "capital improvement" and "public purpose" requirements of Constitution.

Affirmed.

1. Municipal Corporations ⇨722

It is within statutory power of a city to make available industrial sites which may be of benefit to municipality and to lease them on terms which are advantageous to public welfare of city. AS 29.10.132(c).

2. Municipal Corporations ⇨869, 873

Issuance of general obligation bonds to finance a 20-year improvement program providing for purchase of a site and construction of a manufacturing and processing facility to be leased to a private corporation, where significant restrictions and controls were retained by city over corporation's operations, did not constitute a violation of statute prohibiting the state or a political subdivision from lending its credit or borrowing money for use of a private corporation. AS 37.10.085.

3. Municipal Corporations ⇨911

Land and building to be obtained by municipality through issuance of general obligation bonds under a 20-year improvement program providing for purchase of a site and construction of a manufacturing and processing facility, where city's real ownership of structure would increase as years of rental payment went by, constituted "capital improvements" within Constitution providing that no debt shall be contracted by a political subdivision unless for capital improvements. Const. art. 9, § 9.

See publication Words and Phrases for other judicial constructions and definitions.

4. Municipal Corporations ⇨911

In determining whether a community development plan financed through issuance of general obligation bonds fulfills "public purpose" requirement of Constitution, test is whether plan is so unreasonable as to transgress limitations of Constitution. Const. art. 9, § 6.

5. Municipal Corporations ⇨910

Although development of industry within a community through issuance of general obligation bonds is not always an unmixed blessing, as it may impose burdens on other public facilities, it is hard to see how municipality, contrary to "public purpose" provision of Constitution would be hurt by location of an industry within its boundaries, where its plight is that of an eroding economic community and where city fathers and voters of community feel that a plan of action is necessary. Const. art. 9, § 6.

Eric E. Wohlforth, of McGrath & Wohlforth, Anchorage, for appellant.

Burton C. Biss, Anchorage, for appellees.

OPINION

Before DIMOND, Acting Chief Justice, and RABINOWITZ, BONEY, and CONNOR, Justices.

AGO 559893

CONNOR, Justice.

This case questions the validity of a general obligation bond issue for the purpose of encouraging industrial development within a municipality. This is a declaratory judgment action in which appellant, in his capacity as a resident of and owner of real and personal property in the City of Palmer, seeks to have declared invalid the issuance of bonds by the city. These bonds were authorized at a special election at which the proposition carried by a vote of 248 in the affirmative and 7 in the negative. The proposition submitted to the voters was as follows:

PROPOSITION NO. 1

Shall the City of Palmer, Alaska, issue general obligation bonds in an amount not to exceed Four Hundred Fifty Thousand Dollars ($450,000.00) for the following purpose: Under a 20-year improvement program providing for the purchase of a site and the construction of a manufacturing and processing facility within the City of Palmer. All said general obligation bonds shall mature within twenty years from the date of issue and bear interest at a legal rate.

After the proposition was approved by the voters, the city entered into an agreement with Huskey Manufacturing Corporation, a manufacturer or assembler of industrial housing, low-cost residential housing and mobile homes, by which the corporation agreed that it would in the future enter into a lease and occupy the building to be constructed, for a period of not less than 20 years, to keep its raw materials within the city limits in order to render it subject to personal property taxation, to employ not less than 80% of its personnel from the Palmer area, to maintain training facilities for its employees, and to maintain on-the-job training programs under federal and state auspices. It also agreed, as a condition to entering into a lease, that it would use the public utilities owned by the city, as far as they are available. The company agreed that the paved parking lot adjacent to the building should be available at all reasonable times for public recreational uses. The agreement also provides that the rental shall be fixed in such an amount that the total cost of the project, including the sums necessary to amortize the bonds sold to finance the project, shall be payable over a 20-year period under a reasonably uniform schedule through the term of the lease. In short, the city would procure or make available land and a structure for the use of the lessee, using the bond proceeds to accomplish this end.

This case obviously has been brought for the purpose of testing the validity of the bond issue and to determine whether the bonds are marketable. The record is somewhat one-sided in that all of the evidence was presented by the city, although the witnesses for the city were cross-examined by counsel for appellant. On the other hand, the legal questions have been thoroughly argued and briefed. Unlike the situation in Ault v. Alaska State Mortgage Association, 387 P.2d 698 (Alaska 1963), we do find the record sufficient for determining the legal issues presented in this case.[1] Unlike *Ault*, where a summary judgment was entered, this case went to a trial on

1. In Jefferson v. Asplund, 458 P.2d 995, 998 (Alaska 1969), this court held that an actual controversy is a prerequisite to the granting of declaratory relief under the Alaska statute permitting declaratory judgment actions. We further cited with approval the definition of "controversy" found in the opinion by Chief Justice Hughes in Aetna Life Insurance Company of Hartford, Conn. v. Haworth, 300 U.S. 227, 57 S.Ct. 461, 81 L.Ed. 617 (1937):

> "A 'controversy' in this sense must be one that is appropriate for judicial determination. * * * A justiciable controversy is thus distinguished from a difference or dispute of a hypothetical or abstract character; from one that is academic or moot. * * * The controversy must be definite and concrete, touching the legal relations of parties having adverse legal interests." (Citations omitted.)

AGO 559894

the merits under the provisions of Rule 57(a), Rules of Civil Procedure.[2]

The testimony and evidence presented show a pattern of serious economic problems which the City of Palmer is seeking to overcome. The City Council in the agreement to lease makes a recital of its findings about the economic plight of the City of Palmer and its environs. The pattern which emerges from the evidence is that over the course of the last several years the economic growth of Palmer has been nil. The Palmer Comprehensive Development Plan of 1967, prepared by the city, discloses a high year-round rate of unemployment. Virtually no manufacturing exists in the City of Palmer. At one time coal mines were operated in the Palmer area, but these have been shut down because Elmendorf Air Force Base and Fort Richardson, the prime consumers of coal, now utilize natural gas for heating and the generation of electricity. The closure of the mines has resulted in a loss of payroll for the Palmer area estimated at something over one million dollars per annum. Lumber processing has ceased in the Palmer area, with a loss of about 20 jobs. Various other business activities have moved out of the Palmer area recently, including the Matanuska Valley Cooperative Association, the Sears & Roebuck store, and other businesses. Palmer has recently been declared a depressed area by the federal government. It is in an effort to combat this declining economy that the city has proposed the issuance of bonds, the erection of a manufacturing building, and its lease to a private corporation. It is estimated that the proposed project, when fully operational, would employ approximately 65 to 110 persons on a full-time basis.

IS THERE AN UNLAWFUL LENDING OF CREDIT?

[1,2] It is asserted that the bond issue and plan of action violates AS 37.10.085,[3] which prohibits either the state or a political subdivision to lend its credit for the use of a private corporation, or to borrow money for the use of a private corporation. We note at the outset that the city is not handing money directly to a private

2. "Rule 57. Declaratory Judgments - Judgments by Confession. (a) Declaratory Judgments. The procedure for obtaining a declaratory judgment pursuant to statute shall be in accordance with these rules, and the right to trial by jury may be demanded under the circumstances and in the manner provided in Rules 38 and 39. The existence of another adequate remedy does not preclude a judgment for declaratory relief in cases where it is appropriate. The court may order a speedy hearing of an action for a declaratory judgment and may advance it on the calendar."

Many actions such as the one in the instant case have been entertained by other state courts.

"Municipal financing legislation and projects have frequently been questioned in taxpayer suits, on the ground that they violate state constitutional provisions prohibiting the use of public funds or credit for purposes which are not 'public.' Often such suits are brought by industrialists and others who seek prior judicial approval of a project. [Footnotes omitted.] In most cases, the projects and legislation have been upheld. [Newberry v. City of Andalusia, 257 Ala. 49, 57 So.2d 629 (1952); Wayland v. Snapp, [232 Ark. 57], 334 S.W.2d 623 (Ark.1960); Dycke [sic] v. City of London, 288 S.W.2d 648 (1956); Miller v. Police Jury, 226 La. 8, 74 So.2d 391 (1954); City of Frostberg [Frostburg] v. Jenkins, 215 Md. 9, 136 A.2d 852 (1957); Village of Deming v. Hosdreg Co., 62 N.M. 18, 303 P.2d 920 (1956); Holly v. City of Elizabethton, 193 Tenn. 40, 241 S.W. 2d 1001 (1951); McConnell v. City of Lebanon, 203 Tenn. 498, 314 S.W. 2d 12 (1958). *Contra*, State v. Town of No. Miami, 59 So.2d 779 (Fla.1952); State ex rel. Beck v. City of New York, 161 Neb. 223, 82 N.W.2d 239 (1957).]" 70 Yale Law J. 789, at 791 and n. 15, "The 'Public Purpose' of Municipal Financing for Industrial Development."

3. "Financial aid to corporations by state or political subdivision. Neither the state nor a political subdivision of the state may (1) make a subscription to the capital stock of a corporation; (2) lend its credit for the use of a corporation; or (3) borrow money for the use of a corporation."

AGO 559895

corporation. Nor is it pledging that its credit or taxing powers may be used to make good the indebtedness of a private person in contravention of the Alaska Constitution.[4] It is within the statutory power of a city to make available industrial sites which may be of benefit to the municipality and to lease them on terms which are advantageous to the public welfare of the city. AS 29.10.132(c).[5] Since significant restrictions and controls are retained by the City of Palmer over Huskey Manufacturing Corporation's operations, the bond issue in question is not violative of AS 37.10.085. These controls and restrictions were imposed upon the corporation to insure the effectuation of the public purpose objective of this bond issue. Roe v. Kervick, 42 N.J. 191, 199 A.2d 834 (1964). We think that the question of whether the public credit is being pledged for a private purpose is also comprehended under the broader question of whether a public purpose is served by the bond issue and plan for its expenditure, which is discussed below.

IS THE PROJECT A CAPITAL IMPROVEMENT?

The contention is made that the indebtedness would violate Article IX, § 9, of the Alaska constitution[6] which requires that such debt can be incurred only for capital improvements. It is argued that in City of Juneau v. Hixson, 373 P.2d 743 (Alaska 1962), this court laid down a strict test of what constitutes a "capital improvement," rendering that term synonymous with "public works of a permanent character." Because an industrial development project is not clearly within that category, it is said that the plan before us must fail.

We do not read the *Hixson* case so narrowly. There we struck down a bond issue because no capital improvement would have resulted from the expenditure of the proceeds. The vice in the *Hixson* case was that raw land would have been acquired with the proceeds and would then have been donated to the State of Alaska as a proposed capitol site. As a result of the plan, the City of Juneau would have been left with no tangible asset in place of the indebtedness. Furthermore, the State of Alaska had entered into no agreement for and had not otherwise shown an interest in the acquisition or use of any capitol site.

[3] By contrast, in the case before us the City of Palmer will own a tangible asset. The plan is that the indebtedness shall be retired out of the rental money received over the life of the bond issue. The land and building fulfill the definition of "capital improvements" which was stated in the

4. Alaska Const., art. IX, § 6:
"Public Purpose. No tax shall be levied, or appropriation of public money made, or public property transferred, nor shall the public credit be used, except for a public purpose."
The courts which have upheld bonding projects as a legitimate exercise of power by the political subdivisions have held that a statute which pledges only project revenues does not pledge the public credit, and, therefore does not lend the public credit in aid of anyone. Newberry v. City of Andalusia, 257 Ala. 49, 57 So.2d 629 (1952); Wayland v. Snapp, 232 Ark. 57, 334 S.W.2d 633 (1960); Bennett v. City of Mayfield, 323 S.W.2d 573 (Ky.1959).

5. "City properties. * * *
(c) The council, in order to make sites available for new industries which will benefit the municipality, may likewise acquire, own and hold such sites, including real property, either inside or outside the corporate limits and may sell, lease or dispose of them upon the terms and conditions as it considers advantageous to the civic welfare of the city, to persons who will agree to install, maintain and operate a beneficial new industry. Sites acquired under this paragraph and any right, equity, claim or title acquired by the municipality to real property sold to it for delinquent taxes are not 'property acquired, owned or held for or devoted to a public use' as used herein."

6. Alaska Const., art. IX, § 9:
"Local Debts. No debt shall be contracted by any political subdivision of the State, unless authorized for capital improvements by its governing body and ratified by a majority vote of those qualified to vote and voting on the question."

AGO 5591896

Hixson case[7] as being "associated with value represented by real or personal property in some form and with relative permanency." 373 P.2d, at 747. There is here no giving away of the asset. On the contrary, the city's real ownership of the structure should increase as the years of rental payment go by. Even if the tenants should default, the building probably would be susceptible to a number of other beneficial uses. We conclude, therefore, that the bond issue and the plan of expenditure does not violate the capital improvement requirement of our constitution.

IS THERE A FULFILLMENT OF PUBLIC PURPOSE?

Article IX, § 6, of the Alaska constitution provides that "[n]o tax shall be levied, or appropriation of public money made, or public property transferred, nor shall the public credit be used, except for a public purpose." It is asserted that the bond issue and the plan for its expenditure violates this provision.

In DeArmond v. Alaska State Development Corporation, 376 P.2d 717 (Alaska 1962), this court noted that the term "public purpose" is one of great imprecision. As we said there,

> "We believe that it would be a disservice to future generations for this court to attempt to define it. It is a concept which will change as changing conditions create changing public needs. Whether a public purpose is being served must be decided as each case arises and in the light of the particular facts and circumstances of each case." 376 P.2d at 721.

The technique used by most courts is that of looking to the entire factual and governmental context to determine whether a particular plan of action serves a public purpose.[8] In the area of industrial development bond issues, numerous decisions have upheld such plans.[9] There is much criticism which can be leveled against a community using its public borrowing capacity to sponsor or induce the location of private industry within its boundaries. Many of these plans have been attacked on grounds of public policy, but they have been sustained frequently by the courts.[10] It is true that such plans are susceptible to abuse. Municipalities have been known to go bankrupt after having induced an industry to come to them under such a plan.[11] There are dangers that an industry locating in a community may end up dominating the political and economic processes. On the

7. In City of Juneau v. Hixson, 373 P.2d 743 (Alaska 1962), this court defined "capital improvement" as follows:

> "The trial court was correct in holding that the bond issue herein was not for a capital improvement. Assuming for the moment that the expenditure of the money could accomplish the desired objective, the end product would lack most of the attributes usually associated with the completed public project for which general obligation bonds have been sold. No permanent asset in the form of real or personal property would accrue to the city. The property acquired by the proceeds would be donated to the state. No thing of value would remain the property of the city. No improvement of general use or service to the taxpayers of the city would have been created by the expenditure. No tangible security for the bonded indebtedness would have been created - in fact, the total security would have been reduced by the removal of some seven acres of downtown property from the city's tax rolls." 373 P.2d, at 748.

8. See Note, "Legal Limitations on Public Inducements to Industrial Location," 59 Colum.L.Rev. 618 (1959).

9. Newberry v. City of Andalusia, 257 Ala. 19, 57 So.2d 629 (1952); Wayland v. Snapp, 232 Ark. 57, 334 S.W.2d 623 (1960); Dyche v. City of London, 288 S.W.2d 678 (Ky.1956).

10. Although courts have split on the validity of revenue bond plans, the weight of authority is in their favor. Pinsky, "State Constitutional Limitations on Public Industrial Financing: An Historical and Economic Approach," 111 U. of Pa.L.Rev. 265, 276 n. 63 (1963).

11. Long-run economic and social changes are ever present sources of financial risk. Population shifts or widespread economic recession may render unworkable fiscal policies that were once considered sound. These risks, however, are inevitable concomitants of public decision making.

AGO 559897

other hand, it is recognized that the location of an industry in a particular community may have widespread economic benefits and that these do fulfill the public purpose and the general welfare of the community, broadly conceived. The tendency in most of the modern case law is to broaden the notion of public purpose to include such projects as the one contemplated by the City of Palmer.[12]

In Walker v. Alaska State Mortgage Association, 416 P.2d 245 (Alaska 1966), and in Suber v. Alaska State Bond Committee, 414 P.2d 546 (Alaska 1966), such broad notions of public purpose were applied. As we observed in the *Suber* case,

> "The basic objective of government is to protect and promote the health, safety and general welfare of the people. When a condition of affairs appears in the state which presents a threat to the accomplishment of that objective, the government has the right, and the obligation, to cope with such threat by whatever measures, within constitutional limits, that are necessary or appropriate." 414 P.2d, at 551–552.

[4] The role of the courts in matters of this kind is relatively limited. Our function is not to determine whether, as prudent burghers, we might think this plan wise. City of Juneau v. Hixson, supra. The test which we must apply is whether the plan is so unreasonable as to transgress the limitations of our constitution. If the plan of action were plainly foolhardy, or if it amounted to the pledging of credit or the giving away of assets without any corresponding discernible benefit, we might be persuaded to strike down the plan. But that is not the case here.

[5] The benefits from the plan of the City of Palmer may be enjoyed in part by some individuals more than by others. But collective advantages to the community at large can be perceived quite readily. Although the development of industry is not always an unmixed blessing, as it may impose burdens upon other public facilities, it is hard to see how the City of Palmer could be hurt by the location of an industry within its boundaries. Its plight at the moment is that of an eroding economic community. If the city fathers and the voters of the community feel that this plan of action is necessary, it is not for us to retard them. It is within their legislative province to determine whether the advantages outweigh the risks.

Because we think the public purpose of the project has been demonstrated, we find the bond issue valid.

Affirmed.

12. In the cases applying the public purpose doctrine and the public aid limitations to the fields of transportation, recreation, and parking, courts have placed considerable emphasis on the public importance of the project and the urgency of the need for public financing. Pinsky, supra note 10.

AGO 559898

ROBERT J. KUTAK
HAROLD L. ROCK
WILLIAM T. CAMPBELL
ALLAN JAY GARFINKLE
THOMAS A. WOODWARD
GLEN A. BURBRIDGE
RICHARD L. WEILL
JOHN E. NUSSELMAN
ALLACE H. JOHNSON
RICHARD A. SPELLMAN
STEVEN B. HUFF
GREGORY DUBOIS ERWIN
THOMAS J. MCCUSKER
GEORGE H. KRAUSS
MAUREEN E. MCGRATH
HUGH W. MENULTY, JR.
KENNETH J. STUART
DIRK W. deROOS
ANGELO P. PARKER
J. MICHAEL GOTT&CHALK
KENNETH E. ILTZ
JAMES D. KRUYDEL
JOHN J. WAGNER
DONALD A. KRESS
DANIEL S. HOROWITZ
PAUL R. TUFT
RONALD T. PFEIFER
GREGORY W. STARSON
JOHN E. HUBBARD
HARRY D. DIXON, JR.
JOE E. ARMSTRONG
WILLIAM E. HOLLAND
RICHARD D. CIMINO
GARETH G. MORRIS
RAVEN N. P. BELL
PAUL D. LUDD
JOEL T. BOEHM
TERRENCE J. FERGUSON
J. GREGORY H. EDEN
LARRY L. CARLILE
SARAH J. PENN

LAUREN M. RUMALD
PATRICIA J. WINTER
LINDSEY MILLER LERMAN
JOYCE A. DIXON
DIANNE L. STODDARD
TIMOTHY J. KINCAID
JOHN C. MINAHAN, JR.
FRED M. GREGURAS
PAUL E. BELITZ
DENIS P. BURKE
SCOTT C. HOYT
DANIEL S. REYNOLDS
DAVID A. JACOBSON
P. THOMAS POOLE
J. THOMAS MARTEN
D. CHARLES SHOEMAKER
KENNETH R. DODDS
WALTER L. GRIFFITHS
THOMAS B. KOLLEY
JO E. BASS
FRANK A. TAYLOR
RANDALL R. ELEY
CURTIS L. CHRISTENSEN
MICHAEL J. CURRY
LOREN E. DESSONVILLE
DAWN R. DUVEN
JANE E. DENBERGER
FELICIA C. FLOWERS
LYNNE A. FRIEDEWALD
DENNIS L. HOLSAPPLE
FRANK M. SCHEPERS
JULIA G. GINSBURG
CLIFTON R. JESSUP, JR.
DAVID A. GARDELS
CHRISTIAN I. MALABI
JEDD S. PALMER
SHEILA A. PHILLIPS
MOLLY M. ROMERO
PATRICIA A. SCHUETT
STEVEN W. SELINE
JUDY A. WEIL
DENNIS B. WILSON

ROMAN L. HRUSKA
WILLIAM GRODINSKY
FRANK L. BURBRIDGE
GAIL E. BURBRIDGE
COUNSEL

ROMAN L. HRUSKA
THE OMAHA BUILDING
1650 FARNAM STREET
OMAHA, NEBRASKA 68102
(402) 346 6000

ATLANTA
1200 STANDARD FEDERAL SAVINGS BUILDING
ATLANTA, GEORGIA 30303
404 522-6700

DENVER
1330 COLORADO NATIONAL BUILDING
DENVER, COLORADO 80202
303 534-1330

MINNESOTA
4644 IDS TOWER
MINNEAPOLIS, MINNESOTA 55402
612 338-1440

WASHINGTON
1101 CONNECTICUT AVENUE, N.W.
WASHINGTON, D. C. 20036
202 828-2400

December 14, 1979

Dr. Robert LeResche
Commissioner of Natural Resources
Pouch "M"
Juneau, Alaska 99801

Re: Issuance of Revenue Bonds
by the City of Valdez, Alaska

Dear Dr. LeResche:

Concern has been expressed as to whether Section 37.10.085 of the Alaska Statutes would be violated if the City of Valdez, Alaska, issues its revenue bonds (the "Bonds") and the proceeds thereof were made available for the acquisition and construction of certain economic development facilities and other facilities for general public use necessary for the petroleum refinery to be built by The Alpetco Company ("Alpetco") in the City.

Section 37.10.085 states:

Neither the state nor a political subdivision of the state may

(1) Make a subscription to the capital stock of a corporation;

(2) Lend its credit for use of a corporation; or
(3) Borrow money for the use of a corporation.

This section was discussed in Wright v. City of Palmer, 468 P2d. 326 (Alaska 1970), which involved an issue of general obligation bonds by the City of Palmer to finance manufacturing facilities for Huskey Manufacturing Corporation and the lease of such facilities to Huskey. The Court found that the bond issue did not violate AS §37.10.085 in that no money was being handed directly to the corporation, nor was the City pledging its credit or taxing power to make good the indebtedness of a private person. The Court did not find unreasonable the determination of the City that the facilities were to serve a public purpose.

Because the Wright decision involved general obligation bonds it is very strong authority to the effect that the issuance of revenue bonds by the City of Valdez for facilities to be used by a private corporation would not violate §37.10.085. The Alaska Supreme Court recognized in Wright the theory that a statute which pledges only project revenues does not pledge the public credit and therefore does not lend the public credit in aid of anyone. This confirms the position of the Supreme Court in De Armond v. Alaska State Development Corporation, 376 P2d. 717 (Alaska 1962) wherein the Court held that the Alaska State Development Corporation could borrow funds to aid in industrial development. The primary theory in upholding this power was that the credit of the state was not pledged and therefore no public funds or credit were involved.

This is further made clear by Section 11 of Article IX of the Alaska Constitution which states:

> The restrictions on contracting debt do not apply to debt incurred through the issuance of revenue bonds by a public enterprise or public corporation of the State or a political subdivision, when the only security is the revenues of the enterprise or corporation. The

restrictions do not apply to indebtedness to be paid from special assessments on the benefited property, nor do they apply to refunding indebtedness of the State or its political subdivisions.

Based on our review of the Constitution, statutes and case law of the State of Alaska, we are of the opinion that the issuance of the Bonds as contemplated by Resolution No. 7953 of the City of Valdez would not be in violation of §37.10.085 of the Alaska Statutes.

Kutak Rock & Huie

AGO 559901

ALASKA INTERSTATE COMPANY
P. O. Box 6554
HOUSTON, TEXAS 77005

O. CHARLES HONIG
CHAIRMAN OF THE BOARD

December 14, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, Alaska Interstate Company, is a 75.45% shareholder of Alaska Petrochemical Company which is a partner in The Alpetco Company ("Alpetco"). Alpetco was established as of October 1, 1979, to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between the State of Alaska and Alaska Petrochemical Company. Alaska Petrochemical Company has made certain commitments today to Alpetco to provide assurances to the Commissioner of Natural Resources of the State of Alaska (the "Commissioner") that at least $23.4 million in Total Project Costs (as defined in the Royalty Oil Contract) actually will have been expended by a certain date. The other partners in Alpetco have provided similar commitments in respect of an additional $76.6 million in expenditures.

To provide further assurances to the Commissioner, the undersigned commits that if, and to the extent, Alaska Petrochemical Company should fail, in whole or in part, to fulfill Alaska Petrochemical Company's commitment relating to expenditures in accordance with its terms, the undersigned hereby commits to fulfill at least its pro rata share of such commitment, and if needed, hereby commits to fulfill all of Alaska Petrochemical Company's commitment hereunder.

The above commitment of the undersigned is made, with similar commitments by the shareholders of the partners in Alpetco other than Alaska Petrochemical Company, solely for the purpose of providing the Commissioner assurances that at least $100 million in Total Project Costs actually will have been expended prior to the time crude oil is available to the State of Alaska for delivery to Alpetco under the Royalty Oil Contract.

This letter replaces our letter on this same subject which was dated December 13, 1979.

Yours very truly,

ALASKA INTERSTATE COMPANY

O. Charles Honig

AGO 559902

ALASKA PETROCHEMICAL COMPANY
3700 BUFFALO SPEEDWAY
HOUSTON, TEXAS 77098
TELEPHONE 713 840-1243 TELEX 791461

December 18, 1979

Dr. Robert E. LeResche
Commissioner
Department of Natural Resources
Pouch "M"
Juneau, Alaska 99811

HAND DELIVER

Re: Agreement for the Sale and Purchase of State Royalty Oil between Alaska Petrochemical Company and the State of Alaska dated February 22, 1978

Progress Report #18

Dear Commissioner LeResche:

Pursuant to Article 4.2.3 of the above referenced Agreement (the "Agreement"), Buyer's Progress Report for the month ending November 30, 1979 is as follows:

1. Compliance with Article 10.2 of the Agreement:

Although this Progress Report No. 18 covers the month ending November, 1979, Alpetco delivered letters, reports, and other documents to the Commissioner of Natural Resources on December 13, 1979 in support of Alpetco's compliance with Article 10.2(3)(a)-(h) of the Agreement. Such material was hand delivered to the Commissioner and the State's advisors in Seattle, Washington.

In addition to the material submitted to the Commissioner on December 13, 1979, Alpetco is today submitting supplemental material in further support of Alpetco's compliance with Article 10.2(3)(d) and (e) of the Agreement. Such material is attached hereto and enclosed by reference.

AGO 559903

601 WEST 5TH AVENUE, ANCHORAGE, ALASKA 99501, TELEPHONE 907 272-1517, TELEX 090-25157

2. Engineering, Design and Construction:

During November, engineering work continued in support of the project's December 18 contract "benchmark" requirements.

On November 19, 1979 Alpetco submitted to the Commissioner and Mr. Thomas Cook, Director of Division of Minerals and Energy Management, copies of all material state, local and federal permit applications as outlined in Commissioner LeResche's letter to Gordon Cain dated September 27, 1979.

On December 7, 1979, the Alpetco Draft Environmental Impact Statement and Appendices were published in the Federal Record.

On December 7, 1979, Alpetco signed an Engineering Construction Contract with Thyssen Rheinstahl Technik GmbH of Dusseldorf, West Germany and Foster Wheeler Energy Corporation of Linden, New Jersey. Under the terms of this agreement, Thyssen and Foster Wheeler will provide Alpetco with a fixed price for the construction of the refinery and in addition will give Alpetco a completion and performance guarantee for the project. Thyssen and Foster Wheeler will be the prime contractor for the project.

No construction activities took place during the month of November or during the first part of December, 1979.

3. Marketing:

Charter Oil (Alaska), Inc. has entered into an agreement with The Alpetco Company, a joint venture partnership of Alaska Petrochemical Company, Charter Oil (Alaska), Inc. and E. F. Hutton (Alaska) Inc. to purchase 70% of the output of the Valdez facility. This contract is effective December 1, 1979.

4. Financing and Expenditures:

During the month of November and early part December, 1979

The Company obtained financing commitments for the project in the aggregate of $1.7 billion.

On November 19, 1979 the City of Valdez, Alaska unanimously passed Ordinance 7917 authorizing the City to issue tax exempt industrial revenue bonds to finance the Alpetco project. Also, on November 19, 1979, the City Council of Valdez unanimously passed Resolution 7953 authorizing the Mayor of Valdez to execute a commitment to lend Alpetco $600,000,000 from the proceeds of the sale of tax exempt industrial revenue bonds. To support this commitment, the City of Valdez has obtained and underwriting commitment, dated November 19, 1979 from E. F. Hutton & Company to purchase $600,000,000 of the tax exempt bonds.

On December 7, 1979 in consideration of Alpetco entering into the aforementioned engineering and construction contract with Thyssen Rheinstahl Technik GmbH and Foster Wheeler Energy Corporation, Thyssen Rheinstahl Technik delivered a letter committing Thyssen to arrange financing of up to $750,000,000 to cover the cost for the engineering, equipment, materials, construction and other services required for the project.

By letters dated December 13, 1979 the partners of The Alpetco Company have committed, subject to certain conditions, to contribute in the aggregate $350,000,000 in equity to the Alpetco project.

Sincerely,

Gordon A. Cain

Gordon A. Cain
President

GAC/my

cc: Mr. Thomas K. Williams, Commissioner of Revenue (Juneau)
Mr. Thomas Cook, Director Division of Minerals and Energy Management (Anchorage)
Mr. Ed Park, Division of Minerals and Energy Management (Anchorage)

AGO 559905

THE ALPETCO COMPANY
3700 BUFFALO SPEEDWAY
HOUSTON, TEXAS 77098
TELEPHONE 713 840-1243 TELEX 791461

December 13, 1979

Dr. Robert E. LeResche
Commissioner of Natural Resources
State of Alaska
Pouch "M"
Juneau, Alaska 99801

Dear Commissioner LeResche:

The Alpetco Company, a joint venture partnership ("Alpetco") established as of October 1, 1979, by Charter Oil (Alaska), Inc., Alaska Petrochemical Company and E. F. Hutton (Alaska), Inc. (collectively, the "Partners") to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between Alaska Petrochemical Company and the State of Alaska has, in our opinion, satisfied the benchmark provisions of Section 10.2(3) of the Royalty Oil Contract.

Assuming that you concur, we respectfully request that you confirm to us in writing that the provisions of Section 10.2(3) of the Royalty Oil Contract have been satisfied, and that you will give notice to the Lessees (as defined in the Royalty Oil Contract) as soon as practicable but not later than January 18, 1980, pursuant to Section 2.2 of the Royalty Oil Contract, exercising the State of Alaska's right to take its royalty oil in kind, up to 150,000 barrels per day, for sale to The Alpetco Company pursuant to the terms of the Royalty Oil Contract.

In connection with our request to initiate deliveries to us of royalty crude oil beginning July 18, 1980, we are providing with this letter commitments of the Partners that $100 million in Total Project Costs (as defined in the Royalty Oil Contract) will actually be expended within six (6) months following the date on which you give notice to the Lessees of the State's election to take royalty oil in kind for sale to us. In addition, at your request, we are also providing you a letter dated December 12, 1979 setting forth how Alpetco expects that the $100 million will be spent.

Sincerely,

THE ALPETCO COMPANY

By Gordon A Cain
Gordon A. Cain, President

AGO 559906

601 WEST 5TH AVENUE, ANCHORAGE, ALASKA, 99501, TELEPHONE 907 272-1517, TELEX 090-251157

CHARTER OIL (ALASKA), INC.
208 Laura Street
Jacksonville, Florida 32201
904/358-4395

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, Charter Oil (Alaska), Inc., is a 70.0% partner in The Alpetco Company ("Alpetco"). Alpetco, a joint venture partnership, was established as of October 1, 1979 by Charter Oil (Alaska), Inc., Alaska Petrochemical Company and E. F. Hutton (Alaska) Inc. (collectively, the "Partners") to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between Alaska Petrochemical Company and the State of Alaska.

Alpetco has today by letter addressed to the Commissioner of Natural Resources of the State of Alaska (the "Commissioner") notified the Commissioner of Alpetco's compliance with the benchmark provisions of Section 10.2(3) of the Royalty Oil Contract and of its request for the Commissioner to take the appropriate steps to initiate deliveries to Alpetco of crude oil in July, 1980, pursuant to the terms of the Royalty Oil Contract. Under the Royalty Oil Contract, in order for Alpetco to be entitled to delivery of crude oil, $100 million in Total Project Costs (as defined in the Royalty Oil Contract) must first actually have been expended.

The Partners have determined that in order to provide assurances to the Commissioner that at least $100 million in the expenditures for Total Project Costs will be made prior to crude oil deliveries, it would be desirable for the Partners to commit to the Commissioner pro rata in accordance with their partnership interest that such expenditures will be made.

Accordingly, the undersigned commits that by the date (the "Expenditure Date") which is six (6) months following the date on which the Commissioner gives notice to the Lessees (as defined in the Royalty Oil Contract) of the election of the State of Alaska to take royalty oil in kind

for sale to Alpetco, the undersigned will actually expend in Total Project Costs 70.0% of the excess, if any, of $100 million over the amount actually expended in Total Project Costs prior to the Expenditure Date, not to exceed $70,000,000, provided each of the other Partners performs its similar commitment pro rata in accordance with its partnership interest. The commitment of the undersigned hereunder is subject only to the Royalty Oil Contract remaining in effect with Alpetco entitled to the rights of "Buyer" thereunder and to the absence of any statute, rule or order of any governmental or judicial authority which prohibits or prevents, or any governmental or judicial action or proceeding which seeks to prohibit or prevent Alpetco from exercising the rights of "Buyer" under the Royalty Oil Contract.

The above commitment of the undersigned is made, with similar commitments of the other Partners, solely for the purpose of providing the Commissioner assurances that at least $100 million in Total Project Costs actually will have been expended prior to the time crude oil is available to the State of Alaska for delivery to Alpetco under the Royalty Oil Contract.

Attached hereto is a commitment by the sole shareholder of the undersigned in support of the above commitment.

Very truly yours,

CHARTER OIL (ALASKA), INC.

By _____

The Charter Company
208 Laura Street · Post Office Box 2017
Jacksonville, Florida 32231
Telephone 904-358-4111 · Telex 56-239

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speeedway
Houston, Texas 77098

Dear Sirs:

The undersigned, The Charter Company, is the 100% shareholder of Charter Oil (Alaska), Inc. which is a partner in The Alpetco Company ("Alpetco"). Alpetco was established as of October 1, 1979, to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between the State of Alaska and Alaska Petrochemical Company. Charter Oil (Alaska), Inc. has made certain commitments today to Alpetco to provide assurances to the Commissioner of Natural Resources of the State of Alaska (the "Commissioner") that at least $70.0 million in Total Project Costs (as defined in the Royalty Oil Contract) actually will have been expended by a certain date. The other partners in Alpetco have provided similar commitments in respect of an additional $30.0 million in expenditures.

To provide further assurances to the Commissioner, the undersigned commits that if, and to the extent, Charter Oil (Alaska), Inc. should fail, in whole or in part, to fulfill Charter Oil (Alaska), Inc.'s commitment relating to expenditures in accordance with its terms, the undersigned shall fulfill such commitment.

The above commitment of the undersigned is made, with similar commitments by the shareholders of the partners in Alpetco other than Charter Oil (Alaska), Inc., solely for the purpose of providing the Commissioner assurances that at least $100 million in Total Project Costs actually will have been expended prior to the time crude oil is available to the State of Alaska for delivery to Alpetco under the Royalty Oil Contract.

Yours very truly,

THE CHARTER COMPANY

By _____

AGO 559909

ALASKA PETROCHEMICAL COMPANY
3700 BUFFALO SPEEDWAY
HOUSTON, TEXAS 77098
TELEPHONE 713 840-1243 TELEX 791461

December 13, 1979

The Alpetco Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, Alaska Petrochemical Company, is a 23.4% partner in The Alpetco Company ("Alpetco"). Alpetco, a joint venture partnership, was established as of October 1, 1979 by Charter Oil (Alaska), Inc., Alaska Petrochemical Company and E. F. Hutton (Alaska) Inc. (collectively, the "Partners") to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between Alaska Petrochemical Company and the State of Alaska.

Alpetco has today by letter addressed to the Commissioner of Natural Resources of the State of Alaska (the "Commissioner") notified the Commissioner of Alpetco's compliance with the benchmark provisions of Section 10.2(3) of the Royalty Oil Contract and of its request for the Commissioner to take the appropriate steps to initiate deliveries to Alpetco of crude oil in July, 1980, pursuant to the terms of the Royalty Oil Contract. Under the Royalty Oil Contract, in order for Alpetco to be entitled to delivery of crude oil, $100 million in Total Project Costs (as defined in the Royalty Oil Contract) must first actually have been expended.

The Partners have determined that in order to provide assurances to the Commissioner that at least $100 million in the expenditures for Total Project Costs will be made prior to crude oil deliveries, it would be desirable for the Partners to commit to the Commissioner pro rata in accordance with their partnership interest that such expenditures will be made.

Accordingly, the undersigned commits that by the date (the "Expenditure Date") which is six (6) months following the date on which the Commissioner gives notice to the Lessees (as defined in the Royalty Oil Contract) of the election of the State of Alaska to take royalty oil in kind for sale to Alpetco, the undersigned will actually expend in

AGO 559910

501 WEST 5TH AVENUE, ANCHORAGE, ALASKA, 99501, TELEPHONE 907 272-1517, TELEX 090-25157

Total Project Costs 23.4% of the excess, if any, of $100 million over the amount actually expended in Total Project Costs prior to the Expenditure Date, not to exceed $23,400,000, provided each of the other Partners performs its similar commitment pro rata in accordance with its partnership interest. The commitment of the undersigned hereunder is subject only to the Royalty Oil Contract remaining in effect with Alpetco entitled to the rights of "Buyer" thereunder and to the absence of any statute, rule or order of any governmental or judicial authority which prohibits or prevents, or any governmental or judicial action or proceeding which seeks to prohibit or prevent Alpetco from exercising the rights of "Buyer" under the Royalty Oil Contract.

The above commitment of the undersigned is made, with similar commitments of the other Partners, solely for the purpose of providing the Commissioner assurances that at least $100 million in Total Project Costs actually will have been expended prior to the time crude oil is available to the State of Alaska for delivery to Alpetco under the Royalty Oil Contract.

Attached hereto are commitments by the principal shareholders of the undersigned in support of the above commitment.

Very truly yours,

ALASKA PETROCHEMICAL COMPANY

By Gordon A Cain

ALASKA INTERSTATE COMPANY
P. O. Box 6554
HOUSTON, TEXAS 77005

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, Alaska Interstate Company, is a 75.45% shareholder of Alaska Petrochemical Company which is a partner in The Alpetco Company ("Alpetco"). Alpetco was established as of October 1, 1979, to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between the State of Alaska and Alaska Petrochemical Company. Alaska Petrochemical Company has made certain commitments today to Alpetco to provide assurances to the Commissioner of Natural Resources of the State of Alaska (the "Commissioner") that at least $23.4 million in Total Project Costs (as defined in the Royalty Oil Contract) actually will have been expended by a certain date. The other partners in Alpetco have provided similar commitments in respect of an additional $76.6 million in expenditures.

To provide further assurances to the Commissioner, the undersigned commits that if, and to the extent, Alaska Petrochemical Company should fail, in whole or in part, to fulfill Alaska Petrochemical Company's commitment relating to expenditures in accordance with its terms, the undersigned shall fulfill its pro rata share of such commitment.

The above commitment of the undersigned is made, with similar commitments by the shareholders of the partners in Alpetco other than Alaska Petrochemical Company, solely for the purpose of providing the Commissioner assurances that at least $100 million in Total Project Costs actually will have been expended prior to the time crude oil is available to the State of Alaska for delivery to Alpetco under the Royalty Oil Contract.

Yours very truly,

ALASKA INTERSTATE COMPANY

By O. Charles Honig

AGO 559912

E.F. HUTTON (ALASKA) INC.
One Battery Park Plaza
New York, New York 10004
212/742-5000

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, E.F. Hutton (Alaska) Inc., is a 6.6% partner in The Alpetco Company ("Alpetco"). Alpetco, a joint venture partnership, was established as of October 1, 1979 by Charter Oil (Alaska), Inc., Alaska Petrochemical Company and E.F. Hutton (Alaska) Inc. (collectively, the "Partners") to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between Alaska Petrochemical Company and the State of Alaska.

Alpetco has today by letter addressed to the Commissioner of Natural Resources of the State of Alaska (the "Commissioner") notified the Commissioner of Alpetco's compliance with the benchmark provisions of Section 10.2(3) of the Royalty Oil Contract and of its request for the Commissioner to take the appropriate steps to initiate deliveries to Alpetco of crude oil in July, 1980, pursuant to the terms of the Royalty Oil Contract. Under the Royalty Oil Contract, in order for Alpetco to be entitled to delivery of crude oil, $100 million in Total Project Costs (as defined in the Royalty Oil Contract) must first actually have been expended.

The Partners have determined that in order to provide assurances to the Commissioner that at least $100 million in the expenditures for Total Project Costs will be made prior to crude oil deliveries, it would be desirable for the Partners to commit to the Commissioner pro rata in accordance with their partnership interest that such expenditures will be made.

Accordingly, the undersigned commits that by the date (the "Expenditure Date") which is six (6) months following the date on which the Commissioner gives notice to the Lessees (as defined in the Royalty Oil Contract) of the election of the State of Alaska to take royalty oil in kind for sale to Alpetco, the undersigned will actually expend in Total Project Costs 6.6% of the excess, if any, of $100 million over the

amount actually expended in Total Project Costs prior to the Expenditure Date, not to exceed $6,600,000, provided each of the other Partners performs its similar commitment pro rata in accordance with its partnership interest. The commitment of the undersigned hereunder is subject only to the Royalty Oil Contract remaining in effect with Alpetco entitled to the rights of "Buyer" thereunder and to the absence of any statute, rule or order of any governmental or judicial authority which prohibits or prevents, or any governmental or judicial action or proceeding which seeks to prohibit or prevent Alpetco from exercising the rights of "Buyer" under the Royalty Oil Contract.

The above commitment of the undersigned is made, with similar commitments of the other Partners, solely for the purpose of providing the Commissioner assurances that at least $100 million in Total Project Costs actually will have been expended prior to the time crude oil is available to the State of Alaska for delivery to Alpetco under the Royalty Oil Contract.

Attached hereto is the commitment by the sole shareholder of the undersigned in support of the above commitment.

Very truly yours,

E.F. HUTTON (ALAKSA) INC.

By _____

EF Hutton

One Battery Park Plaza
New York, N.Y. 10004
Telephone (212) 742-5000

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, The E. F. Hutton Group Inc., is a 100% shareholder of E. F. Hutton (Alaska) Inc. which is a partner in The Alpetco Company ("Alpetco"). Alpetco was established as of October 1, 1979, to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between the State of Alaska and Alaska Petrochemical Company. E. F. Hutton (Alaska) Inc. has made certain commitments today to Alpetco to provide assurances to the Commissioner of Natural Resources of the State of Alaska (the "Commissioner") that at least $6.6 million in Total Project Costs (as defined in the Royalty Oil Contract) actually will have been expended by a certain date. The other partners in Alpetco have provided similar commitments in respect of an additional $93.4 million in expenditures.

To provide further assurances to the Commissioner, the undersigned commits that if, and to the extent, E. F. Hutton (Alaska) Inc. should fail, in whole or in part, to fulfill E. F. Hutton (Alaska) Inc.'s commitment relating to expenditures in accordance with its terms, the undersigned shall fulfill such commitment.

The above commitment of the undersigned is made, with similar commitments by the shareholders of the partners in Alpetco other than E. F. Hutton (Alaska) Inc., solely for the purpose of providing the Commissioner assurances that a least $100 million in Total

EF Hutton

Project Costs actually will have been expended prior to the time crude oil is available to the State of Alaska for delivery to Alpetco under the Royalty Oil Contract.

Yours very truly,

THE E. F. HUTTON GROUP INC.

By _____

AGO 559916

Howard M. Pack
Vice Chairman of the Board

Seatrain Lines, Inc.

1 Chase Manhattan Plaza
New York, New York 10005

Phone: (212) 964-3400
Telex:
International: 232740 (RCA)
421225 (ITT)
Domestic: 710-581-2334 (TWX)
127-396 (WU)
Cables: SHIPTRAMP or OSTCORPO

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, Seatrain Lines, Inc. is the owner of 100% of Barbour Oil Company, which is a 22.12% shareholder of Alaska Petrochemical Company which is a partner in The Alpetco Company ("Alpetco"). Alpetco was established as of October 1, 1979, to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between the State of Alaska and Alaska Petrochemical Company. Alaska Petrochemical Company has made certain commitments today to Alpetco to provide assurances to the Commissioner of Natural Resources of the State of Alaska (the "Commissioner") that as least $23.4 million in Total Project Costs (as defined in the Royalty Oil Contract actually will have been expended by a certain date. The other partners in Alpetco have provided similar commitments in respect of an additional $76.6 million in expenditures.

To provide further assurances to the Commissioner, the undersigned commits that if, and to the extent, Alaska Petrochemical Company should fail, in whole or in part, to fulfill Alaska Petrochemical Company's commitment relating to expenditures in accordance with its terms, the undersigned shall fulfill its pro rata share of such commitment.

The above commitment of the undersigned is made, with similar commitments by the shareholders of the partners in Alpetco other than Alaska Petrochemical Company, solely for the purpose of providing the Commissioner assurances that at least $100 million in Total Project Costs actually will have been expended prior to the time crude oil is available to the State of Alaska for delivery to Alpetco under the Royalty Oil Contract.

Yours very truly,
SEATRAIN LINES, INC.

By _____

AGO 559917

ALASKA PETROCHEMICAL COMPANY

3700 BUFFALO SPEEDWAY
HOUSTON, TEXAS 77098
TELEPHONE 713 840-1243 TELEX 791461

December 12, 1979

Dr. Robert E. LeResche, Commissioner
Department of Natural Resources
State of Alaska
Pouch M
Juneau, Alaska 99811

Dear Commissioner LeResche:

According to the provisions of our Royalty Oil Contract as amended, Alpetco may purchase royalty crude oil only after 25 months have passed from the Effective Date and $100,000,000 has been expended in Total Project Costs.

The purpose of this letter is to assure you that the $100,000,000 will be spent timely so that notice will be given to the North Slope Producers in time for Alpetco to purchase the royalty crude oil immediately after 25 months have passed from the Effective Date.

The $100,000,000 will be spent in the following manner:

1. The Total Project Costs for administration, engineering, legal and environmental permitting by July 1, 1980, will exceed $25,000,000.

2. As soon as the weather allows and the necessary permits have been issued, we will start site preparation in Valdez. This will involve clearing and leveling the site, building roads and bridges, putting in dykes and drainage ditches, and building or rehabilitating the wharf to unload equipment. The total amount we expect to spend in 1980 for these purposes is $30,000,000. If we are able to start work by May 1, 1980, we expect to spend $2,600,000 of this by July 1, 1980.

3. We will spend an additional amount for one or more of the purposes listed below such that the sum of the amount spent hereunder plus the amounts spent under No. 1 and No. 2 above will exceed $100,000,000:

    a. Order and pay for long delivery items such as compressors, turbines, and electrical equipment.

AGO 559918

Dr. Robert E. LeResche, Commissioner
Department of Natural Resources
State of Alaska

b. Order and pay for steel to be used in fabricating process equipment, tanks, and structures for the facility.

c. Buy a construction camp.

Attached are letters from the owners of Alpetco committing the $100,000,000 required to carry out the above program.

Very truly yours,

ALASKA PETROCHEMICAL COMPANY

By Gordon A Cain
Gordon A. Cain, President

AGO 559919

ALASKA PETROCHEMICAL COMPANY
3700 BUFFALO SPEEDWAY
HOUSTON, TEXAS 77098
TELEPHONE 713 840-1243 TELEX 791461

December 13, 1979

Dr. Robert E. LeResche
Commissioner of Natural Resources
Pouch "M"
Juneau, Alaska 99801

Dear Commissioner LeResche:

When negotiating the terms of its Royalty Oil Contract with the State of Alaska some two years ago, Alaska Petrochemical Company insisted on a right to begin purchasing the royalty oil prior to the time of plant start-up. As you know, we held out for this right so that we could have this crude processed into products we would eventually make in Alaska and thus begin developing market channels for them. We also maintained that we needed the opportunity to benefit from interim crude transactions in order to help the economics of building a large plant in Alaska.

While the Royalty Oil Contract does not require us to do so, we have maintained all along that profits realized from the sale or processing of the crude prior to plant start-up could be critical to the success of the project.

It is therefore with great pleasure that I attach hereto letters from the individual partners of Alpetco representing a commitment to reinvest such profits as required for equity in Alpetco.

Sincerely,

Gordon A. Cain

Gordon A. Cain
President

GAC/my

AGO 559920

601 WEST 5TH AVENUE, ANCHORAGE, ALASKA 99501, TELEPHONE 907 272-1517, TELEX 090-25157

ALASKA PETROCHEMICAL COMPANY
3700 BUFFALO SPEEDWAY
HOUSTON, TEXAS 77098
TELEPHONE 713 840-1243 TELEX 791461

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, Alaska Petrochemical Company, is a 23.4% partner in The Alpetco Company ("Alpetco"). Alpetco, a joint venture partnership, was established as of October 1, 1979, by the undersigned, Charter Oil (Alaska), Inc. and E. F. Hutton (Alaska) Inc. (collectively, the "Partners") to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between Alaska Petrochemical Company and the State of Alaska.

While not required by the terms of the Royalty Oil Contract, Alaska Petrochemical Company hereby agrees to leave in Alpetco or contribute to Alpetco an amount equal to Alaska Petrochemical Company's net profits resulting from the sale and/or processing of interim crude oil by Alpetco, as required for Alaska Petrochemical Company's equity in Alpetco.

Sincerely,

ALASKA PETROCHEMICAL COMPANY

By Gordon A Cain

AGO 559921

601 WEST 5TH AVENUE, ANCHORAGE, ALASKA 99501, TELEPHONE 907 272-1517, TELEX 090-25157

CHARTER OIL (ALASKA), INC.
P. O. Box 4726
Jacksonville, Florida 32201
904/358-4395

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, Charter Oil (Alaska), Inc. is a 70.0% partner in The Alpetco Company ("Alpetco"). Alpetco, a joint venture partnership, was established as of October 1, 1979, by the undersigned, Alaska Petrochemical Company and E. F. Hutton (Alaska) Inc. (collectively, the "Partners") to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between Alaska Petrochemical Company and the State of Alaska.

While not required by the terms of the Royalty Oil Contract, Charter Oil (Alaska), Inc. hereby agrees to leave in Alpetco or contribute to Alpetco an amount equal to Charter Oil (Alaska), Inc.'s net profits resulting from the sale and/or processing of interim crude oil by Alpetco, as required for Charter Oil (Alaska), Inc.'s equity in Alpetco.

Sincerely,

CHARTER OIL (ALASKA), INC.

By _____

AGO 559922

E. F. HUTTON (ALASKA) INC.
One Battery Park Plaza
New York, New York 10004
212/742-5000

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, E. F. Hutton (Alaska) Inc., is a 6.6% partner in The Alpetco Company ("Alpetco"). Alpetco, a joint venture partnership, was established as of October 1, 1979, by the undersigned, Alaska Petrochemical Company and Charter Oil (Alaska), Inc. (collectively, the "Partners") to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between Alaska Petrochemical Company and the State of Alaska.

While not required by the terms of the Royalty Oil Contract, E. F. Hutton (Alaska) Inc. hereby agrees to leave in Alpetco or contribute to Alpetco an amount equal to E. F. Hutton (Alaska) Inc.'s net profits resulting from the sale and/or processing of interim crude oil by Alpetco, as required for E. F. Hutton (Alaska) Inc.'s equity in Alpetco.

Sincerely,

E. F. HUTTON (ALASKA) INC.

By _____

AGO 559923

PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

ALASKA PETROCHEMICAL COMPANY
3700 BUFFALO SPEEDWAY
HOUSTON, TEXAS 77098
TELEPHONE 713 840-1243 TELEX 791461

December 13, 1979

Dr. Robert E. LeResche
Commissioner
Department of Natural Resources
State of Alaska
Pouch "M"
Juneau, Alaska 99811

Re: Article 10.2(3) of the Agreement for the Sale and Purchase of State Royalty Oil between Alaska Petrochemical Company and the State of Alaska dated February 22, 1978 (the "Agreement")

Dear Commissioner LeResche:

At our meeting with you on December 5, 1979 in Juneau, we submitted documentation which we believe satisfied all of the December 18, 1979 "Benchmarks" of the above Agreement except those relating to financia' commitments. You and your attorney, Frederick H. Boness, Esq., made comments and suggestions regarding our submission.

Today we submit the following materials:

(i) A Product Sales Contract revised to reflect Mr. Boness' comments and which, taken together with the Joint Venture Agreement, will result in payment of at least the floor price at all times after start-up.

(ii) Materials which comply with Article 10.2(3)(d) and (e) relating to the financial commitments. These materials include equity commitments from the Joint Venturers and loan commitments from various partners and other important commitments.

(iii) A revised binder which includes the above materials as well as those submitted on December 5, 1979.

(iv) A letter of even date transmitting letters from major chemical and petrochemical companies expressing interest in Alpetco's petrochemical feedstocks and possible downstream petrochemical facilities.

AGO 559924

(v) An executed copy of the Joint Venture Agreement between Alaska Petrochemical Company, Charter Oil (Alaska), Inc. and E. F. Hutton (Alaska) Inc.

Because of the Joint Venture Agreement, we request your approval to the Assignment of the Agreement from Alaska Petrochemical Company to the joint venture, The Alpetco Company.

We are also submitting, under separate cover as Volume II, notice that The Alpetco Company exercises its right to purchase the maximum quantity of State Royalty Oil available under the Agreement beginning July 18, 1980.

We believe we have successfully complied with all of the December 18, 1979 Benchmarks in the Agreement. The Alpetco Company, its partners, their attorneys and other advisors are ready to answer any questions and submit such additional information as you may require.

Very truly yours,

Gordon A. Cain

Gordon A. Cain
President

GAC:lu

Enclosures

ARTICLES 10.2(3)(a) - (h)

INDEX

Benchmark Requirement	Date Submitted to Commissioner
(3) Within eighteen (18) months after the Effective Date:	
(a) Expend or commit to expend or cause contractually bound third parties to expend or commit to expend at least Ten Million Dollars ($10,000,000.00) in Total Project Costs.	12/5/79
(b) Negotiate sale terms with prospective purchasers of products from the Petrochemical Facility; delineate product requirements, production ratios and quantities for the range of products to be produced from the Petrochemical Facility; and draft contracts for the sale of products from the Petrochemical Facility.	12/5/79
(c) Enter into contracts for the sale of at least seventy percent (70%) of the product output from the Petrochemical Facility.	12/5/79
Note: Revised contract to reflect Mr. Boness' comments	12/13/79
(d) Obtain or cause contractually bound third parties to obtain written commitments to lend or invest at least One Billion Five Hundred Million ($1,500,000,000.00) in the aggregate for payment of Total Project Costs.	12/13/79
(e) Obtain a commitment or commitments for interim financing for the construction of the Petrochemical Facility.	12/13/79
(f) Complete and file an Environmental Impact Assessment on the Petrochemical Facility.	11/19/79
(g) Complete and file all material state, local and federal permit applications.	11/19/79
(h) Complete plant design and optimization necessary to obtain a definitive project cost estimate ("definitive" meaning a cost estimate containing no more than fifteen percent (15%) variance in anticipated costs).	12/5/79

AGO 559926

Article 10.2(3)(a)

"Expend or commit to expend or cause contractually bound third parties to expend or commit to expend at least ten million dollars ($10,000,000) in total project costs."

A summary schedule showing total project cost expenditures of $10,632,217.48 and contractual commitments totaling $745,012.50 for a total of $11,377,229.98 is enclosed.

Also enclosed is a copy of Peat, Marwick, Mitchell & Co.'s audit report prepared for the State of Alaska at the State's request confirming Alpetco's expenditures and contractual commitments totaling $11,377,229.98. We understand that Peat, Marwick, Mitchell & Co. has sent a copy of this audit directly to the Commissioner.

We believe that Alpetco has fully complied with this benchmark requirement.

PEAT, MARWICK, MITCHELL & Co.
CERTIFIED PUBLIC ACCOUNTANTS
4300 ONE SHELL PLAZA
HOUSTON, TEXAS 77002

State of Alaska
Department of Natural Resources
and
The Board of Directors
Alaska Petrochemical Company:

At your request, we have performed the procedures enumerated below with respect to total project costs (as defined in the Agreement for the Sale and Purchase of State Royalty Oil between Alaska Petrochemical Company and the State of Alaska dated February 22, 1978, as amended May 17, 1978) for the period January 1, 1975 through November 30, 1979. We understand that you have requested these procedures to assist you in verifying compliance with the terms of Article 10.2(3)(a) of the Agreement, and our report is not to be used for any other purpose. The procedures we performed are summarized as follows:

1. We read the Agreement and made inquiries of Alaska Petrochemical Company personnel concerning the development of total project costs information pursuant to the Agreement.

2. The Company reported to us that total project costs expended or committed to be expended as of November 30, 1979 were $11,377,229.98, as follows:

Expenditures by Alaska Petrochemical Company	$ 8,480,807.36
Expenditures by shareholders of Alaska Petrochemical Company	1,151,410.12
Expenditures by former project engineering firm	1,000,000.00
Commitments to expend of Alaska Petrochemical Company and/or The Alpetco Company, a joint venture formed October 1, 1979 by and among Alaska Petrochemical Company, E. F. Hutton (Alaska), Inc. and Charter Oil (Alaska), Inc.	745,012.50
	$ 11,377,229.98

AGO 559928

3. For the expenditures of Alaska Petrochemical Company, we examined supporting documentation, including the cash disbursements journal, cancelled checks, invoices and/or other documents for 91% ($7,688,210.10) of such project costs. The remaining 9% consisted of a large number of small dollar items.

4. For the expenditures of the direct and indirect shareholders of Alaska Petrochemical Company and the expenditures of the former project engineer, we obtained written confirmations of such project costs directly from such shareholders and project engineer.

5. For the commitments to expend, we examined executed contracts and/or unpaid invoices dated on or before November 30, 1979.

Because the above procedures were not sufficient to constitute an examination in accordance with generally accepted auditing standards, we do not express an opinion on any of the individual amounts referred to above. However, in connection with the procedures referred to above, no matters came to our attention that caused us to believe that the total project costs reported by the Company, as described herein, should be adjusted.

Peat, Marwick, Mitchell & Co.

December 3, 1979

Summary Schedule of Expenditures and

Commitments to Expend for Alpetco's Total Project Costs

Through November 30, 1979

The following total project cost data is submitted in compliance with Article 10.2(3)(a) of the Agreement.

I. Expenditures through November 30, 1979

(A)	Total project costs expended by Alaska Petrochemical Company for the period July 14, 1977-November 30, 1979	$ 6,823,761.85
(B)	Total project costs expended by The Alpetco Company, a partnership of Charter Oil (Alaska), Inc., Alaska Petrochemical Company and The E.F. Hutton (Alaska), Inc. for the period October 1, 1979-November 30, 1979	$ 1,657,045.51
(C)	Total project costs expended by shareholders of Alaska Petrochemical Company for the period January 1, 1975-December 18, 1979	$ 1,151,410.12
(D)	Total project costs expended by Brown and Root, Inc. (former project engineers for Alaska Petrochemical Company)	$ 1,000,000.00
	Sub-total expenditures through November 30, 1979	$10,632,217.48

II. Commitments to Expend at December 1, 1979

(A)	Contractual Commitments	
	(1) E.F. Hutton & Company	$ 410,000.00
	(2) M.B. Carmichael - Employment Contract	90,000.00
	(3) CCC/HOK-Dowl - Accrued Retainage	190,715.46
	Sub-total, Contractual Commitments	$ 690,715.46

AGO 559930

(B) Other commitments:

(1)	Accounts payable	$ 54,297.04
	Sub-total, Other Commitments	54,297.04
	Sub-total, Commitments at December 1, 1979	$ 745,012.50
Total Expenditures and Commitments at December 1, 1979		$11,377,229.98

Note: In order to provide information to The State of Alaska prior to December 18, 1979, this report was prepared as of November 30, 1979. Expenditures and/or commitments made by the Buyer or "contractually bound third parties" from December 1 to December 18, 1979 have not been included but qualify to be included, if such is later deemed advisable. In addition, Total Project Costs have been expended, incurred or committed to be expended by the Buyer and other parties which are not included in the above summary and are not presently reported, because this amount is substantially in excess of the $10,000,000.00 required by Article 10.2 (3)(a). Buyer reserves the right to determine these expenditures at a later date, if necessary to meet benchmark requirements.

Article 10.2(3)(b)

"Delineate product requirements, production ratios, and quantities for the range of products to be produced from the petrochemical facility; draft contracts for the sale of products from the petrochemical facility; and negotiate sale terms with prospective purchasers of products from the petrochemical facility."

A substantial amount of process optimization and market analysis by Company personnel and outside consultants has enabled Alpetco to delineate the products to be produced in the petrochemical facility. The attached schedule indicates the range of products that can be produced from the facility depending on current market requirements. As indicated, additional processing facilities are proposed in Stages II and III to further upgrade petrochemicals produced in Stage I.

We are not enclosing copies of draft contracts for the sale of products or material relating to negotiations of sale terms with prospective purchasers because we believe that the executed contract submitted in compliance with Article 10.2(3)(c) evidences full compliance with these benchmark provisions.

"...delineate product requirements, production ratios and quantities for the range of products to be producted from the Petrochemical Facility;..."

STAGE I

Initial Product Slate	Range of Output B/D	% (Avg)	Projected 1985 Demand (B/D)*	% Demand Supplied By The ALPETCO Company
Unleaded Gasoline:				
Premium	48,100 - 63,300	38.1	847,000	9.4%
Regular	19,300 - 28,000	16.2		
Jet Fuel/ Arctic Diesel	13,600 - 34,100	16.3	599,000	3.4%
No. 4 Fuel	10,000 - 12,000	7.5	N/A	N/A
Clarified Oil	4,500 - 6,000	3.6	N/A	N/A
Subtotal Fuels	119,450	81.7		
Benzene	2,500	1.7	50,200	5.0%
Toluene	5,600	3.8	25,200	22.2%
Xylenes	6,200	4.2	21,900	28.3%
Paraffinic Naphtha	11,200 - 13,700	8.6	277,000	4.5%
Subtotal Chemicals	26,750	18.3		
TOTAL LIQUID PRODUCTS	146,200	100.0		

STAGE II

The second stage of project development will involve the upgrading of benzene and ethylene into ethylbenzene and styrene. This will require further investment in an ethylbenzene plant. In addition, propylene may be converted into oxoalcohols.

STAGE III

Depending on future market conditions, the third stage of the project will be development of an ethylene plant processing Alpetco's naphtha feedstock and/or North Slope gas liquids, if and when such liquids are available.

* Demand for fuel products was estimated by Sherman H. Clark Associates for PAD V. Demand for aromatics in Japan and on the West Coast and Japanese imports of naphtha estimated by Chem Systems, Inc.

AGD 559933

The ALPETCO Company

"...draft contracts for the sale of products from the petrochemical facility, and negotiate sale terms with prospective purchasers of products from the petrochemical facility."

Please refer to the executed product sales contract submitted in compliance with Article 10.2(3)(c) as evidence of compliance with this Article 10.2(3)(b).

AGO 559934

Article 10.2(3)(c)

"Enter into contracts for the sale of at least seventy percent (70%) of the product output from the petrochemical facility."

Enclosed is a fifteen year term product sales contract executed between The Alpetco Company and Charter Oil (Alaska), Inc. for seventy percent (70%) of the product output from the petrochemical facility. As a seventy percent partner in the project, Charter is an experienced and capable marketer of refined petroleum and petrochemical products. Charter presently markets approximately 400,000 B/D of products worldwide.

This contract has been revised since our meeting on December 5, 1979 to reflect comments made at that time by Mr. Boness.

We believe that we are in full compliance with this benchmark requirement.

• Non completion: Thyssen Co. th
• Operational risk: JV. venture agreement 4.03p20.

TABLE OF CONTENTS

		Page
Parties		1
ARTICLE I	DEFINITIONS	1
	(a) AFRA	1
	(b) ASTM	1
	(c) Barrel	1
	(d) Laydays	2
	(e) Terminal	2
	(f) Refining	2
	(g) B/D	2
ARTICLE II	PURCHASES AND PAYMENT	3
	2.01 Purchases	3
	2.02 Purchase Price	3
	2.03 Change in Pricing Formula	3
ARTICLE III	DELIVERY, MEASUREMENTS AND QUALITY	7
	3.01 Delivery and Title	7
	3.02 Quantity	7
	3.03 Quality	7
	3.04 Inspector	7
	3.05 Cargo specifications	8
ARTICLE IV	VESSEL MOVEMENT	9
	4.01 Forecasted Scheduling	9
	4.02 Naming of Vessels	9
	4.03 Arrival Notice	10
	4.04 Notice of Readiness	10
	4.05 Laytime	11
	4.06 When Laytime Ends	11
	4.07 Demurrage	11
	4.08 Berth	12
ARTICLE V	TERM AND TERMINATION	13
	5.01 Term	13
	5.02 Default	13
	5.03 Further Action	14

PRODUCT SALES AGREEMENT

Between

CHARTER OIL (ALASKA), INC.
a Florida corporation

and

THE ALPETCO COMPANY

Dated as of December 1, 1979

PRODUCT SALES AGREEMENT

THIS AGREEMENT is made as of December 1, 1979 by and between CHARTER OIL (ALASKA), INC., a Florida corporation, ("Buyer"), and THE ALPETCO COMPANY, a Florida general partnership composed of Charter Oil (Alaska), Inc., Alaska Petrochemical Company and E. F. Hutton (Alaska) Inc., ("Seller").

This agreement documents an arrangement by which Seller will sell and deliver and Buyer will purchase petroleum products as provided herein.

NOW, THEREFORE, the parties agree as follows:

ARTICLE I

DEFINITIONS

1.01 As used in this agreement, the following words or phrases have the following meanings:

(a) AFRA. "AFRA" is the Average Freight Rate Assessment.

(b) ASTM. "ASTM" is the American Society for Testing and Materials.

(c) Barrel. A "barrel" is a U.S. barrel of 42 gallons measured at 60° Fahrenheit.

		Page
ARTICLE VI	FORCE MAJEURE	15
	6.01 Excused by Law	15
	6.02 Matters or Things	15
	6.03 Unreasonable Demands of Labor . .	16
	6.04 Time Lost by Force Majeure	17
ARTICLE VII	ASSIGNMENT	18
	7.01 Assignment by Seller	18
	7.02 Assignment by Buyer	18
ARTICLE VIII	PROVISIONS OF GENERAL APPLICATION . . .	19
	8.01 Waiver	19
	8.02 Choice of Law	19
	8.03 Amendment	19
	8.04 Headings and Sections	19
	8.05 Written Notices	19

ARTICLE II

PURCHASES AND PAYMENT

2.01 Purchases. During the term of this agreement, Seller will sell and deliver to Buyer and Buyer will purchase, receive and pay for seventy percent (70%) of the Refinery's total daily output presently estimated to be the following products and associated volumes.

Product	Approx. Volume
Unleaded Gasoline	67,400 B/D
Jet Fuel/Arctic Diesel	34,100 B/D
No. 4 Fuel Oil	12,000 B/D
Clarified Oil	6,000 B/D
Benzene	2,500 B/D
Toluene	5,600 B/D
Xylene	6,200 B/D
Naptha	13,200 B/D
Sulfur	260 T/D
All other Products	

2.02 Purchase Price. Buyer will pay to Seller a purchase price, FOB the Terminal, for all product delivered hereunder equal in amount to the higher of Market Price as defined in Section 2.02(a) below, or Floor Price as defined in Section 2.02(b) below.

(a) Market Price. The Market Price for all products delivered during a calendar month shall be equal to the sum of the Market Price for each product. The Market Price

(d) Laydays. "Laydays" are the five days upon which the parties agree pursuant to section 4.01 and set aside for a vessel's arrival at the Terminal.

(e) Refinery. The "Refinery" shall mean the refinery and petrochemical complex which Seller intends to construct at Valdez, Alaska, U.S.A.

(f) Terminal. The "Terminal" shall mean the marine loading terminal which Seller intends to construct at Valdez, Alaska, U.S.A.

(g) B/D. "B/D" means Barrels per day.

for each product delivered during a calendar month shall be equal to the posted price, herein defined for each product, less transportation cost from the posting site to Valdez, Alaska, multiplied by the volume of each product delivered.

For unleaded gasoline and diesel fuel, the posted price shall be equal to the simple average of Los Angeles, California rack prices reported for the prior month by the Lundberg Survey for the following companies: ARCO, Douglas, Gulf, Pacific, Powerine, Tosco, and USA PetroChem. The transportation cost for unleaded gasoline and diesel fuel shall be equal to the prior month's average AFRA postings for 32,000 ton clean tankers from Valdez to Los Angeles, California, plus $.50 per barrel escalated monthly using the Department of Commerce Wholesale Price Index.

For all other products, the posted price and transportation cost shall be based on independently determined public postings representative of existing market conditions and satisfactory to both parties.

(b) Floor Price. Notwithstanding anything else to the contrary herein, when the requirements of Section 5.01 have been satisfied, Buyer shall pay to Seller as and when due 70% of the sum of all of Seller's costs, expenses, obligations and liabilities including but not limited to costs, expenses, obligations and liabilities relating to the operation and maintenance of the Refinery or otherwise. Seller shall furnish to Buyer at least thirty days prior to the first delivery of product hereunder and at least ten days prior to the commencement of each calendar month thereafter an estimate

of the Floor Price for all products for the next calendar month and within twenty-five days after the end of each calendar month Seller's Floor Price on an actual basis during the preceding calendar month. If the Floor Price is higher than the aggregate amounts determined under Section 2.02(a), payments shall be made on the basis of Seller's estimate of Floor Price and shall be adjusted on the basis of the actual Floor Price when it has been determined.

If during any calendar month the Floor Price for all products exceeds the Market Price for all products and excess shall be credited to Buyer's account and shall bear interest accrued and added to principal monthly at the prime rate in effect from time to time at Chemical Bank New York from the last day of such month until utilized as a credit as hereinafter provided. During any calendar month in which the Market Price for all products exceeds the Floor Price for all products, any credit which Buyer may have in its account (including interest) will be used to pay the portion of the purchase price for all products equal to the amount by which the Market Price for all products exceeds the Floor Price.

2.03 Change in Pricing Formula. If either or both of the two postings in subsections 2.02(a) should be changed, so that the prices contemplated by those subsections no longer are available in the Lundberg Survey, the parties shall negotiate in good faith on an alternate publicly posted price to be used as the basis of pricing, and if no

such alternate is reasonably available, on a substitute pricing formula. Any cargo lacking a price as a result of a change in the postings requiring negotiations under this section shall be priced at the last price calculated pursuant to section 2.02 the day before the posting was (postings were) changed. However, if the change in the posting is descriptive only and does not affect the substance of the price reported, then the new posting shall be substituted for the old for purposes of subsections 2.02(a), and no negotiations under this section shall be necessary.

2.04 Payment. On the twentieth (20th) day of each calendar month after the first delivery of product hereunder, Seller shall furnish Buyer its estimate of the purchase price for all product to be delivered to Buyer hereunder during such calendar month. On the first day of each succeeding calendar month, Buyer shall pay to Seller the full amount of such estimated purchase price, in immediately available U.S. dollar funds, by transferring such funds to Seller's account at a bank selected by Seller. By the tenth (10th) day of each month, any adjustment necessary to reconcile the estimated purchase price and the Market Price for the prior month, pursuant to section 2.02(a), shall be made. By the twenty-fifth (25th) day of each month, any adjustment necessary to reconcile the estimated purchase price (as adjusted above) and the Floor Price for the prior month, pursuant to section 2.02(b), shall be made.

ARTICLE III

DELIVERY, MEASUREMENTS AND QUALITY

3.01 Delivery and Title. Deliveries of product shall be made at the Terminal into vessels provided by Buyer. Title to and risk of loss of product shall pass from Seller to Buyer as the product reaches the flange of the receiving vessel's permanent hose connection.

3.02 Quantity. The quantity of product delivered shall be determined from measurements taken of the still storage tanks before and after the delivery to Buyer's vessel. Measurements shall be adjusted to 60° Fahrenheit in accordance with ASTM Petroleum Measurements Tables (ASTM Designation S-1250, Abridged Table 7).

3.03 Quality. All products shall be of commercial quality, and shall be verified from samples taken from the still storage tanks prior to loading. All tests for quality shall be conducted in accordance with the then latest ASTM-approved methods.

3.04 Inspector. The tests for quantity and quality called for by sections 3.02 and 3.03 shall be performed by an independent petroleum inspector selected by Seller and acceptable to Buyer. The inspector shall perform

the tests in its own laboratories with its own personnel, and shall not merely certify the results of tests performed by others. The cost of the testing shall be shared equally by the parties. The determinations made by the inspector shall be final and binding on both parties.

3.05 Cargo Specifications. If Seller anticipates that a cargo of product will not meet the specifications of Exhibit 1, Seller will notify Buyer at least 72 hours prior to loading at which time Buyer shall have the right to accept or reject the cargo. In the event Buyer accepts the cargo, a new price will be negotiated at that time, but in no event shall the new price be less than the applicable Floor Price.

ARTICLE IV

VESSEL MOVEMENT

4.01 Forecasted Scheduling. The parties anticipate rateable cargoes of product during each month will be delivered hereunder. By the 15th day of the preceding month, Seller shall nominate separate Laydays for the cargoes to be delivered in the 1st half of the succeeding month. By the twentieth day of the preceding month, Seller shall nominate separate Laydays for the cargoes to be delivered in the last half of the month. In each case Buyer shall accept or reject the nomination, and if it rejects it, the parties shall select alternate Laydays. When the Laydays have been selected, Buyer shall notify Seller of the size of the cargo pursuant to section 2.01.

4.02 Naming of Vessels. Buyer shall, in conformity with the Laydays, identify each vessel by notice to Seller given in writing at least seven days in advance of the commencement of the Laydays, stating the name and size of the vessel to be loaded and giving full instructions regarding it. If a ship's schedule is disrupted, Buyer shall notify Seller immediately of any change in its expected arrival date; but such notice shall not modify the Laydays agreed upon pursuant to section 4.01 unless Seller agrees to a change.

AGO 559947

4.03 Arrival Notice. Buyer shall give (or cause to be given) Seller written notices of the expected day and hour of arrival of each vessel at least 72, 48 and 24 hours before arrival.

4.04 Notice of Readiness. Upon arrival at customary anchorage in Valdez, the master or his agent shall give Seller notice that the vessel is ready to load cargo, berth or no berth, whenever that may be so. If such notice is given within the Laydays, laytime shall commence six hours after receipt by Seller of such notice, or when the vessel is all fast at the Terminal, whichever first occurs. If the notice of readiness is given prior to the beginning of the Laydays, Seller may accept the vessel if it wishes, but has no obligation to do so until the first of the Laydays; but if Seller does accept the vessel, laytime shall commence when the vessel is all fast at the Terminal. If the notice of readiness is given after the last of the Laydays, Seller shall use its best efforts to berth the vessel as soon as possible after notice of readiness is given, but Seller shall not be liable for any demurrage incurred while the vessel is waiting to berth. However, where delay is caused to the vessel getting into berth after giving notice of readiness for any reason over which Buyer or Seller have no control, such delay shall not count as used laytime.

4.05 Laytime. There shall be allowed as laytime for loading 36 hours. Any delay in loading due to the vessel's condition or breakdown or inability of the vessel's facilities to load cargo within the time allowed shall not count as used laytime. If regulations of Seller or of port authorities prohibit loading of the cargo at night, time so lost shall not count as used laytime. If Buyer prohibits loading of the cargo at night, time so lost shall count as used laytime.

4.06 When Laytime Ends. Laytime shall end when the delivery hoses are disconnected after completion of loading or when the vessel is released by Seller or its agent, whichever last occurs.

4.07 Demurrage. Seller shall pay Buyer demurrage per running hour, prorata for a part thereof, of laytime used in excess of allowed laytime as set forth herein at the rate set forth in AFRA in effect on the date of loading for the size vessel being loaded in the case of vessels on term charter to Buyer, and at the rate set forth in the charter party for vessels under spot charter. If, however, demurrage shall be incurred by reason of fire, explosion or

storm, or by a strike, lockout, stoppage or restraint of labor, or by breakdown of machinery or equipment in or about the Refinery or Terminal, the rate of demurrage shall be reduced one-half for demurrage so incurred. Seller shall not be liable for any demurrage for delay caused by strike, lockout, stoppage or restraint of labor of master, officers and crew of the vessel or tugboats or pilots.

4.08 Berth. Seller shall provide a safe berth for Buyer's vessels free of all wharfage, dockage and quay dues, and of sufficient depth to permit Buyer's vessels to always lie safely afloat at all times of tide, and which such vessel can at all times safely reach and leave.

ARTICLE V

TERM AND TERMINATION

5.01 Term. The term of this agreement shall commence on the date of the first cargo loading after completion of the Refinery and Terminal and continue f[redacted] thereafter p[redacted]t this agreement is subject to Buyer's final approval of definitive documents relative to long-term loan of funds for the Refinery, the Terminal and related facilities and to the execution by December 18, 1980 of such documents by Alpetco and the lenders providing such funds.

5.02 Default. If Buyer defaults in the performance of any of its obligations hereunder, Seller may give Buyer written notice of such default, and if such default is for the payment of money and it is not cured within ten days thereafter, or if such default is other than for the payment of money, and such default is not cured within thirty days thereafter Seller may either (a) take such legal action against Buyer as Seller may deem appropriate to enforce Seller's rights and Buyer's obligations hereunder and to recover any damages which Seller may have suffered by reason of Buyer's default, or (b) terminate this agreement by written notice to Buyer. In the event Seller defaults in the performance of any of its obligations hereunder, Buyer may take such legal action it deems appropriate to enforce Buyer's rights and Seller's obligations hereunder, but in no event shall Buyer's remedies include the right to terminate this agreement.

5.03 Further Action. Upon expiration of this a ee-ment, the parties shall continue to be obligated to take such further action as is reasonable to account fully each to the other, and to be obligated to deliver such documents as reasonably may be required to effectuate the purposes of this agreement, in order to carry to conclusion the transactions contemplated hereunder and promptly to settle the accounts between them.

ARTICLE VI

FORCE MAJEURE

6.01 Excused by Law. No failure or omission to carry out or to observe any of the terms, provisions or conditions of this agreement except such failure or omission caused by or resulting from economic duress shall give rise to any claim by one party against the other, or be deemed to be a breach of this agreement, if such failure or omission is excused by law.

6.02 Matters or Things. No failure or omission by Seller to carry out or to observe any of the terms, provisions or conditions of this agreement shall give rise to any claim by Buyer or be deemed to be a breach of this agreement, if such failure or omission is caused by a matter or thing not within the control of Seller and Seller is not able to overcome such matter or thing by the exercise of due diligence. By way of illustration, but not by way of limitation, the following are matters or things embraced by the foregoing definition: war (whether declared or not, and whether or not involving the United States), hostilities, blockade, acts of the public enemy or of belligerents; sabotage, insurrection, riot or disorder; arrest or restraint of peoples; embargoes, export or import restrictions or rationing or allocation (whether imposed by law, decree or regulation, or by voluntary cooperation of industry at the instance or request of any government or person(s) purporting to act therefor); interference [redacted] (whether civil or military, whether de jure or de facto, and whether purporting

to act under some constitution, decree, law or otherwise); failure or refusal of any government, governmental agency or organization owned or controlled by any government, to supply oil; act of God, fire, earthquake, storm, lightning, ice, tidal wave or perils of the sea; loss of tanker tonnage due to sinking by belligerents or to governmental taking (whether or not by formal requisition); barratry of the master and/or crew, collisions, strandings, accidents of navigation or breakdown or injury of vessels, and all dangers or accidents of the seas, canals or rivers and the navigation of vessels or whatever nature even when occasioned by negligence, default or error in judgment of the pilot, master, mariners, seamen or other servants of the vessel's owners; deviation of vessels to save life or property; accidents to or closing of harbors, docks, canals, channels or other assistance to or adjuncts of shipping or navigation; epidemic or quarantine; strikes or combinations of workmen, [redacted] f wells, pipes, storage facilities, refineries, installations, machinery or other facilities; unavailability of feedstock or necessary products; unavailability of materials or equipment; the failure of a manufacturing facility to operate for any reason beyond the reasonable control of the party which owns or operates such facility; shutdown of plant required for prudent maintenance.

6.03 Unreasonable Demands of Labor. Nothing in this Article VI shall be construed to require Seller to accede to demands of labor or labor organizations which it considers unreasonable in its absolute discretion.

6.04 Time Lost by Force Majeure. At the option of Seller the term of this agreement shall be extended for a period of time equal to any period that Seller's performance hereunder was excused by the provisions of Sections 6.01 and 6.02; provided Seller gives Buyer notice of such election within sixty days after the cessation of such excused performance.

ARTICLE VII

ASSIGNMENT

7.01 Assignment by Seller. Seller may at any time (and without the consent of Buyer) pledge, mortgage, collaterally assign, grant a security interest in or otherwise hypothecate all or any portion of its rights under this agreement, but only for the purpose of providing the security deemed necessary by Seller in order to finance the cost of constructing the Refinery and Terminal and related working capital. Except as provided above, Seller shall not pledge, mortgage, assign, grant a security interest in or otherwise transfer or hypothecate all or any portion of its rights or obligations hereunder without the prior written consent of Buyer.

7.02 Assignment by Buyer. Buyer may at any time (and without the consent of Seller) assign all or any portion of its rights under this agreement to any corporation, all the outstanding stock of which is owned by Buyer or a corporation which owns directly or indirectly all the outstanding stock of Buyer. Notwithstanding any such assignment, Buyer shall remain liable hereunder for all its obligations unless specifically released by Seller. Except as provided above, Buyer shall not pledge, mortgage, assign, grant a security interest in or otherwise transfer or hypothecate all or any portion of its rights or obligations hereunder without the prior written consent of Seller.

ARTICLE VIII

PROVISIONS OF GENERAL APPLICATION

8.01 Waiver. Failure of either party to insist upon strict observance of or compliance with all of the provisions of this agreement in one or more instances shall not be deemed to be a waiver of its rights to insist upon observance or compliance with the other provisions hereof, or of the same provision on a subsequent occasion.

8.02 Choice of Law. This agreement shall be governed by and construed in accordance with the laws of the State of Alaska.

8.03 Amendment. This agreement may be amended only in a writing signed by the party to be bound.

8.04 Headings and Sections. The headings contained in this agreement are for convenient reference only, and shall not in any way effect the meaning or interpretation of this agreement. All references to sections are to sections of this agreement, unless the context indicates otherwise.

8.05 Written Notices. All notices required or permitted hereunder shall be in writing and shall be deemed properly given only when received by the party to be served. Notices may be transmitted by TWX or Telex, or United States mail, and addressed as follows:

To Buyer:

Charter Oil (Alaska), Inc.
P. O. Box 4726
Jacksonville, Florida 32202
Telex 568415

To Seller:

The Alpetco Company
3700 Buffalo Speedway, Suite 806
Houston, Texas 77098
Telex 791461

Either party may change its address for purposes of this section by giving written notice to the other of such change in the manner herein provided.

IN WITNESS WHEREOF, the parties hereto have executed this agreement in multiple originals as of the day and year first above written.

CHARTER OIL (ALASKA), INC.

By _____
Title President

THE ALPETCO COMPANY

By Gordon A Cain
Title President

AGO 559958

EXHIBIT I

PRODUCT SPECIFICATIONS

1. BENZENE; TOLUENE, XYLENE

Benzene	ASTM D835-77
Toluene	ASTM D841-77
Xylene	ASTM D845-71

2. PARAFFINIC NAPHTHA

Blended Raffinate from Sulfolane BTX extraction plus n-pentane/isohexane from naphtha prefractionation.

RVP, psia	9 Max.
Sulfur, wt. %	0.05 Max.
Distillation, °F	
Initial Boiling point	90 Min.
50%	205 Min.
End point	360 Max.
Olefins, Vol. %	1 Max.
Aromatics, Vol. %	6.5 Max.
Color, Saybolt	25 Min.

3. GASOLINE

(Must meet Los Angeles Basin gasoline specifications.)

		Premium	Regular
Octane	$\frac{R + M}{2}$	92	89
RVP	Max.	11.5	11.5
	Min.	7.0	7.0
Bromine Number		30 Max. (ASTM D-1159)	30 Max.

4. JET FUEL (JET A-1)

Acidity, total max. mg KOH/g	0.1
Aromatics, vol., max., %	25
Sulfur, Mercaptan, wt., max. %	0.003
Sulfur, total wt., max., %	0.125
Distillation temperature, °F	
10% recovered, max. temp.	400
Final boiling point, max. °F	572
Flash point, min., °F	123
Gravity, max., °API (Min., sp gr) at 60° F	51 (0.7753)

Gravity, min. °API (max., sp gr) at 60°F	37 (0.8398)
Freezing point, max. (°C)	(-50)
Viscosity -30°F(-34.4°C) max., cSt.	15
Net heat of combustion, min., Btu/lb.	18400

5. DIESEL (ARCTIC SPECIFICATION)

Flash point, °F	140 Min.
Cloud point, °F	-60 Max.
Kin. Vis. at 100°F., CS	1.2-2.5
ASTM Distillation, °F	
90% Evaporated at	550 Max.
End point	572 Max.
Carbon residue on 10% Btms.	0.1 Max.
Sulfur, Wt. %	0.2 Max.
Water + Sediment, Wt. %	0.01 Max.
Insolubles, Mg/100 ML	1.5 Max.
Neutralization No., TAN	0.05 Max.
Particulate Mg/L	8 Max.
Cetane No.	45 Min.

6. NO. 4 FUEL

Flash point, °F	130 Min.
Pour point, °F	20 Max.
Water + Sediment, Vol. %	0.5 Max.
Kin. Vis. at 100° F., cST	5.8 to 26.4
Sulfur, Wt. %	0.3 Max.

7. CLARIFIED OIL

Following is the specification for Carbon Black Feedstock. If Clarified Oil is not suitable, it will be sold as Bunker C.

Bureau of Mines Correlation Index (1)	120 Min.
API Gravity at 60°F	3.0 Max.
Ash, %	0.06 Max.
Sediment, %	0.2 Max.
Sulfur, % by Wt.	2.25 Max.
Asphaltenes, % by Wt.	5 Max.
Sodium, ppm	10 Max.
Potassium, ppm	1 Max.
SSU Viscosity at 210°F	70 Max.
Initial Boiling Point, °F	400 Min.

(1) $BMCI = \frac{87,552}{°R} + 473.5 \left(\frac{1}{s.g.}\right) - 456.8$

Where °R = average volumetric boiling point in °F., corrected to 760 mmHg pressure, plus 460

s.g. = specific gravity

8. SULFUR

Purity, Wt. %	99.8 Min.
Color	Bright Yellow

9. COKE

Sulfur, Wt. %	1.8 Max.
Nickel, ppm	9,350
Vanadium, ppm	19,890

The Charter Company
206 Laura Street · Post Office Box 2017
Jacksonville, Florida 32231
Telephone 904-356-4111 · Telex 56-239

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, The Charter Company, is the 100% shareholder of Charter Oil (Alaska), Inc., which is a 70.0% partner in The Alpetco Company ("Alpetco"). Charter Oil (Alaska), Inc. has entered into a Product Sales Agreement dated as of December 1, 1979, (the "Sales Agreement").

In support of Charter Oil (Alaska), Inc.'s obligations under the Sales Agreement the undersigned, if required by the lenders providing funds as long-term loans for Alpetco's refinery and petrochemical project in Alaska, commits to take such actions as are necessary to cause Charter Oil (Alaska), Inc. to fulfill its obligations under the Sales Agreement subject to final approval by the undersigned of definitive documents relating to such long-term loans and to the execution by December 18, 1980, of such documents by Alpetco and the lenders providing such funds.

The above commitment of the undersigned is made solely for the purpose of supporting Charter Oil (Alaska), Inc.'s obligations under the Sales Contract and is not intended for the benefit of any person other than Charter Oil (Alaska), Inc.

Very truly yours,

THE CHARTER COMPANY

By: _____

Article 10.2(3)(d)

"Obtain or cause contractually bound third parties to obtain written commitments to lend or invest at least One Billion Five Hundred Million ($1,500,000,000.00) in the aggregate for payment of Total Project Costs."

Alpetco has obtained written commitments for $1.7 billion for payment of Total Project Costs. The issuers of the commitments and the amounts of each are as follows:

Thyssen Rheinstahl Technik GmbH	$ 750,000,000.00
City of Valdez	600,000,000.00
Partners of The Alpetco Company	350,000,000.00
	$1,700,000,000.00

This amount represents the total anticipated long term financing requirements for the Project. Attached and separately tabbed are letters and related documents to substantiate these financing commitments.

We believe that Alpetco has fully complied with this benchmark.

Thyssen Rheinstahl Technik GmbH - $750,000,000.00

On December 7, 1979 Alpetco entered into an agreement with Thyssen Rheinstahl Technik GmbH (Thyssen) and Foster Wheeler Energy Corporation (Foster Wheeler) for engineering and construction of Alpetco's refinery and petrochemical facility. In consideration of this agreement, Thyssen has given Alpetco its commitment to arrange financing of up to $750,000,000.00.

Thyssen is a member of the Thyssen Group, one of the world's largest industrial corporations, with assets in excess of $8 billion. Headquartered in Dusseldorf, West Germany, Thyssen is experienced in financing and constructing major industrial facilities including refining and petrochemical facilities on a worldwide basis. Thyssen's capability to finance, construct and guarantee this project is underscored in a reference letter from Deutsche Bank, one of the world's largest commercial banks in which Deutsche Bank states:

> "THYSSEN RHEINSTAHL TECHNIK GMBH ranks with our most esteemed customers, we know this Company to be capable of accomplishing and financing the projects it undertakes and we further know it would not enter into liabilities it could not meet."

Included under this tab is Thyssen's commitment letter, Deutsche Bank's letter of reference and the Engineering and Construction Contract executed on December 7, 1979 between Thyssen, Foster Wheeler and Alpetco.

In addition to the above financial commitments of Thyssen, the Engineering and Construction Contract with Thyssen and Foster Wheeler also adds significant other strengths to the viability of the Project. The Thyssen/Foster Wheeler agreement:

1. Eliminates the risk of cost overrun by giving Alpetco a fixed price for construction.

2. Eliminates the risk that construction will not be completed by giving Alpetco a completion guarantee.

3. Eliminates the risk that the facility will not operate by giving Alpetco a performance guarantee.

THYSSEN

Thyssen Rheinstahl Technik GmbH · Postfach 80 23 · 4000 Düsseldorf 1

THYSSEN RHEINSTAHL TECHNIK GMBH

The Alpetco Company
3700 Buffalo Speedway
Houston, Texas 77098
U. S. A.

Thyssen Technik-Haus
Königsallee 106
Düsseldorf

Ihre Zeichen	Ihre Nachricht vom	Unsere Zeichen	Unser Hausruf (Direktwahl) (02 11) 38 03 -	Düsseldorf
		Recht/Dr.W./ho		December 7, 1979

Betreff

Gentlemen:

In consideration of Alpetco entering into the attached Engineering- and Construction-Contract with Thyssen Rheinstahl Technik GmbH (Thyssen), or a Joint Venture consisting of Thyssen and another party nominated by Thyssen, for the engineering, supplies and construction of the facilities of Alpetco's Valdez, Alaska Refinery and Petrochemical Facility (Project), such Project headed by The Alpetco Company (Alpetco) - a Joint Venture partnership owned by Charter Oil (Alaska), Inc., a subsidiary of The Charter Company, Alaska Petrochemical Company and E.F. Hutton (Alaska), Inc. - we hereby commit to arrange financing of up to US$ 750,000,000.-- (sevenhundredandfifty million US-Dollars) to cover cost for the engineering, equipment, materials, construction and other services required for the Project.

Our commitment hereunder is subject to Alpetco's acquiring and contributing to the Project financing of at least US$ 750,000,000.- (sevenhundredandfifty million US-Dollars) by the issuance of industrial revenue bonds, equity investment and other satisfactory forms of financing by Alpetco's partners as are required for the Project implementation.

AGO 559965

Geschäftsführung: Dr. Helmut Gaschwendt (Vorsitzender)
Handelsregister-Nr.: HR B 3311

"best efforts." ?

Definitive agreements for all the financing required shall be entered into by December 18, 1980, on such terms and conditions as are customarily required for similar financings by lenders at such time. If such definitive agreements are not entered into by such date, we reserve the right to terminate our commitment hereunder without any liability on our part.

The financing shall be subject to Alpetco obtaining all necessary approvals and permits required by the responsible authorities for the construction and operation of the Project, the Royalty Crude Oil Contract being in effect and Alpetco having the right to take crude oil not later than July 18, 1980.

Yours faithfully,

THYSSEN RHEINSTAHL TECHNIK
G.m.b.H.

Deutsche Bank
Aktiengesellschaft

To whom it may concern

Filiale Düsseldorf

Postanschrift/Postal Address/Adresse
Postfach/P. O. Box/Boite Postale 11 17
D-4000 Düsseldorf 1
Telephon: (02 11) 88 31
Telex: 8 582 586
Telegramme/Cables/Télégrammes:
deutschbank

Bitte in der Antwort angeben Please quote/Prière d'indiquer	Ihre Zeichen und Nachricht vom Your reference and date/Votre référence et date	Durchwahl/Direct line/Ligne directe	Datum Date
Garantien sey/bö		883 376	9th February, 1978

Reference

Since many years THYSSEN RHEINSTAHL TECHNIK GMBH, Düsseldorf, is experienced in the turn-key implementation of refineries, petro-chemical plants, gas-, oil- and water-pipelines and supplies also complete plants including know-how and engineering for iron-, steel-, raw materials-industry as well as other technical goods and machinery for various industries throughout the world.

THYSSEN RHEINSTAHL TECHNIK GMBH ranks with our most esteemed customers, we know this Company to be capable of accomplishing and financing the projects it undertakes and we further know it would not enter into liabilities it could not meet.

Deutsche Bank AG

Fussangel Janssen

AGO 559967

"binding"

This Contract effective as of 7th day of December , 1979, between, on the one hand,

No recourse on either side. Gin

THYSSEN RHEINSTAHL TECHNIK GMBH
having its registered office in Düsseldorf,
Federal Republic of Germany,
and hereinafter called "THYSSEN",

and

FOSTER WHEELER ENERGY CORPORATION
having an office in Houston, Texas/USA,
and hereinafter called "FOSTER WHEELER",

and on the other hand

THE ALPETCO COMPANY, - a Joint Venture partnership owned by Charter Oil (Alaska), Inc., a subsidiary of the Charter Company, Alaska Petrochemical Company and E.F. Hutton (Alaska), Inc.- , having an office in Houston, Texas/USA, and hereinafter called "ALPETCO"

W I T N E S S E T H

WHEREAS, ALPETCO desires to have constructed a grass roots 150,000 BPCD crude oil refinery and petrochemical facility on property provided by ALPETCO located at Valdez, Alaska, together with financing arrangements for implementation of said construction, hereinafter called the "PROJECT" and

WHEREAS, FOSTER WHEELER AND THYSSEN have entered into a Joint Venture Agreement to associate themselves under the name of FOSTER WHEELER-THYSSEN, Joint Venture, hereinafter called "JOINT VENTURE", for the purpose of implementing the PROJECT on the basis of this contract with ALPETCO, hereinafter referred to as "CONTRACT" and

AGO 559968

WHEREAS, the JOINT VENTURE has responded to ALPETCO's request and has proposed to ALPETCO a procedure, as outlined in this Contract; and

WHEREAS, ALPETCO desires the JOINT VENTURE to undertake certain services hereinafter referred to as "WORK" to develop a fixed price for the turnkey construction of the PROJECT, and to implement the Project; and

WHEREAS, the JOINT VENTURE desires so to do,

NOW, THEREFORE, in consideration of the mutual promises and covenants contained herein, the parties agree as follows:

1.0 SERVICES BY JOINT VENTURE

The JOINT VENTURE shall in accordance with the provisions of this Contract:

1.1 Perform such engineering design and related activities as is necessary to prepare a fixed price for the implementation of the PROJECT.

1.2 Perform with the cooperation of ALPETCO, required activities for development of a Project Labor Agreement with appropriate labor unions to enable JOINT VENTURE to obtain firm quotes from sub-contractors.

1.3 Develop a time schedule for completion and start-up of the PROJECT.

1.4 Obtain all permits and licenses necessary for the performance of JOINT VENTURE's services which are required to be obtained in the name of JOINT VENTURE.

AGO 559969

1.5 Provide engineering specifications acceptable to and not now available from ALPETCO.

2.0 SERVICES BY ALPETCO

ALPETCO shall perform the following services in connection with WORK to be performed under this CONTRACT without cost to JOINT VENTURE. Such services shall include but be not limited to the following:

2.1 Provide any necessary basic design data, engineering reviews and approvals and any other engineering services not to be provided by JOINT VENTURE under Article 1.0. This shall include necessary soil bearing data and foundation design criteria, topographic survey, and proper benchmarks for design and construction.

2.2 Procure all necessary permits, licenses, easements, rights of way, and real property for the construction and operation of the plant other than permits and licenses to be provided by the JOINT VENTURE under subsection 1.4.

2.3 ALPETCO will make available as required by the JOINT VENTURE, the information requested by the JOINT VENTURE resulting from the license agreements and ALPETCO will conclude any license agreements for process licenses by third parties.

2.4 ALPETCO will negotiate and finalize commitments on long term marketing of products from customers at terms and conditions which are acceptable to lending institutions as a collateral for the financing if necessary.

2.5 ALPETCO will arrange the interim construction financing and will cooperate with the JOINT VENTURE in arranging the long term financing. ALPETCO will arrange for the issuing of the City of Valdez Industrial Revenue Bonds.

2.6 Activities specified in 2.1 through 2.4 will be finalized on or before finalization of the JOINT VENTURE's activities as specified in 1.0.

3.0 FIXED PRICE CONTRACT

The parties shall promptly negotiate and finalize by March 31, 1980, the terms and conditions of the definitive Fixed Price Contract. On or before September 1, 1980, the JOINT VENTURE shall propose

a) a fixed price for the project implementation

b) a contractual guarantee for timely completion of the plant,

c) a contractual performance guarantee

and if accepted by ALPETCO within three months, the definitive Fixed Price Contract shall become effective.

4.0 COMPENSATION

ALPETCO shall pay the JOINT VENTURE in the manner and at the times designated in Article 5.0 below the costs and charges specified in attached Annex 1.

5.0 TERMS OF PAYMENT

The JOINT VENTURE shall invoice ALPETCO monthly for costs and charges incurred pursuant to Article 4.0 and ALPETCO shall pay the JOINT VENTURE ten days after presentation of respective invoices all costs and charges incurred by the JOINT VENTURE as per Annex 1 in US-Dollars.

6.0 TERMINATION

6.1 Either party may terminate this Contract under any of the following circumstances:

(i) The Royalty Crude Oil Contract is for any reason terminated or ALPETCO ceases for any reason to be able to receive crude oil in quantities commensurate with the Project,

(ii) The other party fails to perform its obligations under this Contract.

In the event of such termination ALPETCO shall pay to the JOINT VENTURE the amounts specified in Article 5. ALPETCO agrees to release, hold harmless and indemnify the JOINT VENTURE, FOSTER WHEELER, THYSSEN, or their affiliates from any loss, cost, damages or against any claims thereof resulting from ALPETCO's, its successors' and assigns' or any third party's use of such drawings, specifications or other data delivered to ALPETCO pursuant hereof. The provisions of this paragraph will survive the termination or expiration of this Contract.

6.2 If this Contract terminates, or if the Contract expires without having been replaced by the fixed Price Contract, then Thyssen's letter dated December 7, 1979, shall become null and void without any liability thereunder.

7.0 PERIOD OF PERFORMANCE AND VALIDITY OF CONTRACT

7.1. It is presently estimated (but the JOINT VENTURE does not guarantee) that the WORK will be completed by the JOINT VENTURE by September 1, 1980, provided that ALPETCO timely furnishes the information required in Article 2.0 above.

7.2 The validity of this Contract expires three (3) months from the submission of the fixed price to ALPETCO by the JOINT VENTURE.

7.3 If the validity of the Contract expires neither the JOINT VENTURE nor ALPETCO shall have the right of claim against the other party as a consequence of the expiration of this Contract other than those rights expressly agreed upon in this Contract.

8.0 JAPANESE PARTICIPATION

It is contemplated that the JOINT VENTURE will subcontract with Japanese companies acceptable to ALPETCO for the supply of components and services for the PROJECT including transportation to the jobsite.

9.0 REPRESENTATIONS

ALPETCO represents that it undertakes this Contract on an exclusive basis, i.e., ALPETCO will not implement the PROJECT with third parties, unless the JOINT VENTURE will have given its consent or either party will have terminated this Contract pursuant to Article 6.0.

AGO 559973

10.0 WARRANTEES

10.1 ALL WORK performed by the JOINT VENTURE under this Contract which requires correction and ALPETCO having so indicated to the JOINT VENTURE shall be corrected by the JOINT VENTURE provided ALPETCO requests such correction within thirty (30) days after submission of the fixed price to ALPETCO by the JOINT VENTURE. The JOINT VENTURE's responsibility shall be limited solely to redoing its own and subcontractor's own WORK.

10.2 The JOINT VENTURE's warrantees and guarantees stated herein are exclusive and in lieu of all other warranties and guarantees, whether written or oral or implied in the fact or in law, and whether based on statute, contract, tort (including negligence) strict liability or otherwise.

11.0 ACCOUNTING

11.1 The JOINT VENTURE shall keep full and detailed accounts and records in accordance with its established accounting procedure.

11.2 The JOINT VENTURE shall submit to ALPETCO by February 1, 1980 a forecast of monthly expenditures under this Contract.

11.3 The JOINT VENTURE shall permit ALPETCO to have access to and currently to review and audit at all reasonable times all records and accounts relating to costs reimbursable by ALPETCO under this Contract exclusive, however, of any fi xed overlays or fixed rates. If as a result of any review or audit the invoices and statements submitted in accordance with Article 4.0 are found to be in error, such errors shall be adjusted in the next subsequent invoices. Such audits may be made as work progresses and final audit shall be completed within 60 days after completion of the services as provided for herein.

12.0 INSURANCE

The partners of the JOINT VENTURE shall maintain during the performance of the WORK hereunder the insurance required by the applicable jurisdictions.

13.0 BROWN & ROOT, INC.

Prior to the date hereof, BROWN & ROOT, INC. has performed certain services ("B&R SERVICES"). On behalf of ALPETCO in connection with the initial B&R SERVICES, ALPETCO shall defend, indemnify and hold harmless JOINT VENTURE claims, demands, liabilities, damages and courses of action of any nature whatever arising out of or incidental to such B&R SERVICES.

14.0 CONSEQUENTIAL DAMAGES

Notwithstanding anything in this Contract to the contrary, it is agreed that neither party to this Contract, their affiliates and subcontractors shall have no liability, whether in contract, tort, strict liability or otherwise, for loss of product, loss of profit, loss of use or any other indirect or consequential damages.

15.0 GOVERNING LAWS

This Contract will be governed and interpreted under the laws of the State of Florida.

16.0 ENTIRE AGREEMENT/AMENDMENTS

16.1 This Contract and THYSSEN's letter dated December 7, 1979 constitute the entire agreement between the parties hereto relating to the services and supersedes any previous agreement or understanding relating to the services, and shall not be altered or amended except by the written agreement of the parties.

16.2 The validity of this Contract shall not be affected should one or more of its stipulations be or become legally invalid. In such case the invalid clause shall be replaced by a stipulation which is in accordance with the law and which shall be as close as possible to the parties' original intent.

17.0 NOTICES

17.1 All notices required under this Contract shall be in writing and shll be sufficient in all respects if delivered in person or sent by registered mail addressed to :

Foster Wheeler /Thyssen Joint Venture

c/o Thyssen Rheinstahl Technik GmbH
Attention: Mr. Wolfgang Schwarze

Königsallee 106
Postfach 80 23

D 4000 Düsseldorf

and if ALPETCO shall be sufficient in all respect if delivered in person or sent by registered mail addressed to

The Alpetco Company

Attention: Mr. Gordon Cane

3700 Buffalo Speedway, Suite 806

Houston, Texas 77098

17.2 Either party may change the person/or address to which notice shall be given by giving the other party written notice of such change.

IN WITNESS WHEREOF the parties have executed this Contract on the date first written above.

The Alpetco Company

Gordon A. Cane

Joint Venture

Thyssen Rheinstahl Technik GmbH

.....

Foster Wheeler Energy Corporation

.....

ANNEX I

COMPUTATION OF JOINT VENTURE'S COSTS

The JOINT VENTURE will charge their costs to ALPETCO on a cost reimbursable basis including but not limited to:

1. Wages and Salaries

   The wages and salaries, for such time as is devoted to the PROJECT by home office personnel, whether such services are performed in the office abroad, or in the field for personnel such as, but not limited to, managers, engineers, designers, draftsmen, purchasers, expeditors, project accountants, secretaries.

2. Payroll Burdens

   An amount equal to seventy percent (70%) for THYSSEN and an amount equal to forty-five percent (45%) for FOSTER WHEELER's total wages and salaries for payroll burdens to cover the costs of payroll taxes and insurance, group medical and life insurance, as well as pro rata share of the cost to employer of vacation, sick benefits, holiday pay and other employee benefits.

3. Indirect Costs

   An amount equal to one hundred percent (100%) for THYSSEN and an amount equal to one hundred percent (100%) for FOSTER WHEELER's total wages, salaries and payroll burden costs reimbursable in accordance with the sum of section 1. and 2. to cover for the related overhead and indirect office costs.

4. Transportation, Relocation and Travel Expenses

   The cost of transportation, relocation, and travel expenses for personnel engaged in the project in accordance with established policies.

5. Communication Expenses

   Long distance telephone, telegraph, postage, and teletype expenses incurred in the direct prosecution of the project at cost.

6. Prints and Reproduction

   Prints and reproductions in accordance with established rates.

AGO 559978

7. Computer Services

Computer services for the prosecution of technical and commercial programs in accordance with established rates.

8. Third Party Services

Services performed by a third party, such as financial and legal advisers, soil investigation, etc., at cost.

9. Miscellaneous Expenses

Miscellaneous expenses, including, but not limited to, custom printed forms, special book bindings, special drafting room and office materials and supplies, model shop material, freight, express, duties, fees, permits, and any other cost incurred in connection with the project.

City of Valdez, Alaska - $600,000,000.00

On November 19, 1979 the City of Valdez unanimously passed Ordinance 7917 authorizing the City to issue tax exempt industrial revenue bonds to finance the Alpetco project. Also, on November 19, 1979 the City Council unanimously passed Resolution 7953 authorizing the Mayor of Valdez to execute a commitment to lend Alpetco $600,000,000.00 from the proceeds of the sale of tax exempt industrial revenue bonds.

To support this commitment, the City of Valdez has obtained an underwriting commitment, dated November 19, 1979, from E. F. Hutton & Company to purchase $600,000,000.00 of the tax exempt bonds.

Copies of the City Ordinance 7917, Resolution 7953, the City's commitment letter and E. F. Hutton's underwriting commitment follow.

AS 37.10.035

Emergency / 60 days

CITY OF VALDEZ, ALASKA

ORDINANCE NO. 7917

AN ORDINANCE OF THE CITY OF VALDEZ, ALASKA, CREATING ARTICLE II, CHAPTER 9, OF THE VALDEZ CITY CODE ESTABLISHING PROCEDURES FOR ISSUING ECONOMIC DEVELOPMENT BONDS AND MATTERS RELATED THERETO

WHEREAS, the City of Valdez, Alaska is a home rule city and under Section 11 of Article X of the Alaska Constitution may exercise all legislative powers not prohibited by law or by the Charter of the City, and it has been determined that the matters set forth in this Ordinance are not prohibited by law or the Charter; and

WHEREAS, it is necessary and for the best interests of the City to provide employment opportunities and to encourage the economic development of the City, thereby reducing the evils attendant upon unemployment and furthering the welfare and prosperity of the residents of the City; and

WHEREAS, the issuance of revenue bonds to finance in whole or in part the costs of the acquisition, purchase, construction, reconstruction, improvement, equipping, betterment, extension, addition, repair, alteration, rehabilitation, renovation or enlargement of economic development facilities as aforesaid is a public purpose and is a proper exercise of a governmental function of the City; and

WHEREAS, the establishment of procedures for the issuance of such revenue bonds is authorized by the Charter including, but not limited to, Section 14.8, and is necessary and desirable to provide clarity in law and direction for subsequent actions;

NOW, THEREFORE, BE IT ORDAINED BY THE COUNCIL OF THE CITY OF VALDEZ, ALASKA, THAT:

Section 1. Article II, Chapter 9 of the Valdez City Code is hereby created to read as follows:

ARTICLE II - ECONOMIC DEVELOPMENT BONDS

Sec. 9-40. Definitions. Whenever used in this Article unless a different meaning clearly appears from the context:

(1) "bonds" means revenue bonds issued as herein provided.

(2) "Charter" means the Charter of the City as from time to time amended and supplemented.

(3) "City" means the City of Valdez, Alaska.

(4) "construction" of or with respect to a project means and includes the acquisition, purchase, construction, reconstruction, improvement, equipping, betterment, extension, addition, repair, alteration, rehabilitation, renovation or enlargement of the project.

(5) "impact aid payment" or "administrative fee" means the impact aid payment or administrative fee pursuant to Section 9-54 of this Article.

(6) "person" means any individual, partnership, co-partnership, firm, company, corporation (including a public utility), association, joint stock company, trust estate, political subdivision, state agency, or any other legal entity, or its legal representative, agent or assigns.

(7) "project" means any land, building, structure, facility, system, fixture, improvement, addition, appurtenance, machinery and equipment, and any real and personal property deemed necessary in connection therewith, including but not limited to machinery and equipment whether or not now in existence or under construction, which shall be suitable for any of the following:

(a) Any enterprise for the manufacturing, processing or assembling of any agricultural, manufactured or natural resource product.

(b) Any commercial enterprise for the storage, warehousing, distributing, selling or providing of products or services and including research and development therefor.

(c) Any health care institution.

(d) Sport facilities.

(e) Convention or trade show facilities.

(f) Airports, docks, wharves, mass commuting facilities, parking facilities, or storage or training facilities directly related thereto.

(g) Sewage or solid waste disposal facilities or facilities for the furnishing of electric energy, gas or water.

(h) Industrial park facilities.

(i) Air or water pollution control facilities.

(j) Any educational institution.

(8) "project costs" means and includes the sum total of all reasonable or necessary costs incidental to the construction of a

project and the issuance of bonds to finance the project in whole or in part, including without limiting the generality of the foregoing the following, which may be payable by or to the City or any other person:

(i) obligations incurred or assumed by the City or any other person for labor, materials, and equipment in connection with the construction of the project;

(ii) the cost of performance, labor and material bonds and insurance of all kinds that may be required or necessary during the course of construction of the project;

(iii) all costs of architectural and engineering services, including the costs incurred or assumed by the City or any other person for preliminary design and development work, test borings, surveys, estimates and plans and specifications, and for supervising construction, as well as for the performance of all other duties required by or consequent upon the proper construction of the project;

(iv) all costs required to be paid by the City or any other person under the terms of any contract or contracts for the construction or financing of the project;

(v) payment of the initial or acceptance fees of any trustees; the costs of any title search, insurance or opinions; any fees and expenses for recording and filing all documents and instruments in connection with the project and the construction and the financing thereof; and overhead and

administrative expenses properly chargeable to capital or similar accounts in connection with the project;

(vi) payment of the legal, underwriting, financial advisory, rating service and accounting fees and expenses and printing and engraving costs incurred in connection with the authorization, sale and issuance of bonds issued to finance the project in whole or in part and the preparation of all documents in connection with the project and the construction thereof and the issuance of the bonds;

(vii) an initial bond and interest reserve;

(viii). interest to accrue on all bonds issued to finance the project in whole or in part to a date six (6) months subsequent to the estimated date of compietion of the project; and

(ix) the impact aid payment or administrative fee.

(9) "revenues and receipts" of a project or derived from a project includes payments under a lease, sublease, agreement of sale or loan agreement and under notes, debentures, bonds and other secured or unsecured debt obligations of any person executed and delivered to the City or its designee or assignee (including a trustee) pursuant to such lease, sublease, agreement of sale or loan agreement but excluding the impact aid payment or administrative fee.

Sec. 9-41. Legislative Declaration of Purpose. It is hereby determined and declared that the purpose of this Article is to provide a

method for financing the cost of economic development facilities in the City in order to provide employment opportunities and relieve conditions of unemployment and encourage the economic development of the City, thereby reducing the evils attendant upon unemployment and furthering the welfare and prosperity of the residents of the City, and any and all of the same are hereby declared and determined to be public purposes and a proper exercise of a governmental function of the City. It is hereby further determined and declared that each and every matter and thing as to which provision is made in this Ordinance is desirable in order to carry out and effectuate the purposes of the City in accordance with the constitution and statutes of the State of Alaska and the Charter of the City and to issue bonds in accordance with the terms of this Article.

Sec. 9-42. Additional Powers. In addition to other powers which it may have, the City shall have the power under this Article:

(1) To acquire by gift, purchase, lease or sublease, to construct and to finance one or more projects, whether or not now or hereafter in existence, within the City.

(2) To issue its revenue bonds to defray in whole or in part the project costs of any project and to designate an appropriate name for, and all other details of, such bonds.

(3) To rent, lease, sublease, sell or finance any project to any person in such manner that payments to be received with respect to the project shall produce revenues and receipts sufficient to provide for the prompt payment at maturity of principal,

interest and redemption premiums, if any, upon all bonds issued to finance in whole or in part project costs of such project, and without limiting the generality of the foregoing to enter into a lease-leaseback, leveraged leasing, purchase-saleback, loan or other arrangement whereby project costs may be financed.

(4) To pledge the revenues and receipts to be received from a project and its rights to bring actions and proceedings under any lease, sublease, agreement of sale, loan or other instrument for the enforcement of remedies thereunder to the punctual payment of bonds issued to finance in whole or in part project costs of such project, and the interest and redemption premiums, if any, thereon.

(5) To sell and convey any project for such price and at such time (whether prior or subsequent to or concurrently with the payment in full of bonds authorized under this Article) as the Council may determine.

(6) To issue its bonds to refund in whole or in part bonds theretofore issued under this Article, and to extend the term of the refunding bonds beyond the term of the refunded bonds.

Sec. 9-43. Exercise of Powers. The exercise of all powers pursuant to this Article may be authorized by resolution of the Council which may in each instance be adopted at the same meeting, either regular or special or an adjournment of either, at which it is introduced and shall take effect immediately upon adoption.

Sec. 9-44. Bonds. Bonds issued pursuant to this Article may (i) bear interest at such rate or rates payable at such time or times; (ii) be in one or more series; (iii) bear such date or dates; (iv) mature at such time or times not exceeding 40 years from their respective dates; (v) be payable in such medium of payment at such place or places; (vi) carry such registration privileges; (vii) be subject to such terms of redemption at such premiums or otherwise; (viii) be executed in such manner; (ix) contain such terms, covenants and conditions; and (x) be in such form, either coupon or registered, or both, with conversion and reconversion privileges, all as may be prescribed by the resolution of the Council authorizing their issuance; provided that such resolution (a) need not prescribe a definitive interest rate or rates for the bonds but may instead prescribe a maximum interest rate or rates within which the bonds may be sold, (b) need not prescribe the definitive terms upon which the bonds may be redeemed by the City but may instead prescribe minimum and maximum terms of years within which the bonds may be redeemed by the City and the minimum and maximum premiums, if any, payable in the case of such redemptions, (c) need not prescribe the principal amount of the bonds but may instead prescribe a maximum principal amount of bonds to be issued, (d) need not prescribe the definitive principal maturities of or sinking fund payments with respect to the bonds but may instead prescribe minimum and maximum terms of years within which the bonds shall mature or be subject to sinking fund payments and minimum and maximum amounts of such principal securities or sinking fund payments, and (e) need not

designate a trustee and additional paying agents but may instead indicate whether or not a trustee and additional paying agents are to be designated and prescribe qualifications for such trustee and paying agents; provided further that such resolution may appoint the Mayor, City Manager, or such other official as the Council deems advisable, to sell the bonds upon terms and conditions which comply with the provisions of such resolution, and all definitive terms and conditions with respect to the bonds, including the designation of a trustee and additional paying agents, if any, which are not prescribed by the resolution authorizing their issuance shall be established by the terms and conditions upon which the bonds are sold.

Sec. 9-45. Sale of Bonds. Bonds may be sold at public or private sale at such price (which may be at par, at a premium above par or at a discount below par), in such manner and upon such terms and conditions as comply with the provisions of the resolution authorizing the issuance of the bonds, all as may be approved by the official appointed to sell the bonds or by the Council if no such official be appointed.

Sec. 9-46. Interim Receipts or Certificates. Pending the preparation of the definitive bonds, interim receipts and certificates in such form and with such provisions as the Council may determine may be issued to the purchaser or purchasers of bonds sold pursuant to this Article.

Sec. 9-47. Bonds, etc., to be Negotiable Instruments. The bonds and interim receipts or certificates shall be deemed to be securi-

ties and negotiable instruments within the meaning and for all purposes of the "Uniform Commercial Code".

Sec. 9-48. Covenants in Bonds. Any resolution authorizing the issuance of bonds under this Article may provide that the principal of and the interest and premium, if any, on the bonds shall be secured by an indenture of trust covering the revenues and receipts derived from the leasing, subleasing, sale or financing of the project for which the bonds are issued and such other funds and rights, if any, as are assigned and pledged under such indenture of trust. Any such resolution or indenture of trust, or any such lease, sublease, agreement of sale or loan agreement may contain such covenants and provisions as the Council may determine to be advisable, including, but not limited to, covenants and provisions with respect to the project and the bonds, and the security therefor, such as to (a) the application, use and disposition of the proceeds of the bonds and of the revenues and receipts from the project for which the bonds are to be issued, including the creation and maintenance of reserves, if any; (b) the issuance of other or additional bonds relating to the project or any construction of the project; (c) the maintenance and repair of such project; (d) the insurance to be carried thereon and the use and disposition of insurance moneys; (e) the appointment of, or the prescription of qualifications for, any bank or trust company within or outside the State of Alaska, having the necessary trust powers, as trustee for the benefit of the bondholders, paying agent, and bond registrar and the vesting in the trustee of rights, powers, duties, funds and properties for the

benefit of bondholders; (f) the appointment of, or the prescription of qualifications for, any bank or banks or trust company or companies within or outside the State of Alaska, having the necessary trust powers, as additional paying agent or agents for the bonds and the interest thereon; (g) the investment of any funds held under such resolution or indenture of trust; (h) the terms and conditions upon which the holders of the bonds or any portion thereof, or any trustees therefor, are entitled to the appointment of a receiver; and (i) any other matters of like or different character which in any way affect the security or protection of the bonds. Any such resolution and indenture of trust shall be enforceable by any bondholder by appropriate suit, action or proceeding in any court of competent jurisdiction, provided the resolution or indenture of trust under which the bonds are issued may provide that all such remedies and rights to enforcement may be vested in a trustee for the benefit of all the bondholders.

Sec. 9-49. Signatures of Officers on Bonds - Validity of Bonds. The bonds shall bear the manual or facsimile signatures of such officers of the City as may be designated in the resolution authorizing such bonds and such manual or facsimile signatures shall be the valid and binding signatures of the officers of the City, notwithstanding that before the delivery thereof and payment therefor any or all of the persons whose signatures appear thereon have ceased to be officers of the City. The validity of the bonds is neither dependent on nor affected by the validity or regularity of any proceedings relating to the construction of the project for which the bonds are issued. The reso-

lution authorizing the bonds may provide that the bonds shall contain a recital that they are issued pursuant to this Article, which recital shall be conclusive evidence of their validity and of the regularity of their issuance.

Sec. 9-50. Pledge and Lien of Bonds. All bonds issued under this Article shall have a lien upon the revenues and receipts derived from the leasing, subleasing, sale or financing of the project for which the bonds have been issued to the extent such revenues and receipts are pledged pursuant to this Article, and the Council may provide in the resolution authorizing such bonds for the issuance of additional bonds to be equally and ratably secured by a lien upon such revenues and receipts or by a subordinate lien upon such revenues and receipts.

Sec. 9-51. Limited Liability for Bonds. All bonds issued under and pursuant to this Article shall be limited obligations of the City payable solely out of the revenues and receipts derived from the leasing, subleasing, sale or financing of the project with respect to which such Bonds are issued. Bonds issued under this Article are not payable from taxes levied upon the taxable real and personal property in the City and are not a charge against the general credit or taxing power of the City. No holder of any bonds issued under this Article shall have the right to compel any exercise of the taxing power of the City to pay the bonds or the interest or premiums, if any, thereon, and the bonds do not constitute an indebtedness of the City or a loan of credit thereof within the meaning of any constitutional or statutory

provision. It shall be plainly stated on the face of each bond that it has been issued under the provisions of this Article and that it is not payable from taxes levied upon the taxable real and personal property in the City and is not a charge against the general credit or taxing power of the City and does not constitute an indebtedness of the City or a loan of credit thereof within the meaning of any constitutional or statutory provision.

Sec. 9-52. Exemption from Construction and Other Requirements for Public Buildings. The construction of a project shall not be subject to any requirements relating to public buildings, structures, grounds, works or improvements imposed by any ordinance or resolution of the City, or to any other similar requirements, and any requirement of competitive bidding or other restriction imposed on the procedure for award of contracts for such purpose or the lease, sublease, sale or other disposition of property of the City is not applicable to any action taken pursuant to this Article.

Sec. 9-53. Procedures Established as Additional and Supplemental - Limitations Imposed - Effect. The procedures established by this Article are in addition and supplemental to, and the limitations imposed by this Article shall not affect, the exercise of powers conferred by the Charter, any law or any other ordinance. Construction of any projects may be accomplished and financed, and bonds may be issued under this Article for such purposes, notwithstanding that any law or any other ordinance may provide for the construction and financing of a like project, or the issuance of bonds for like purposes, and

without regard to the requirements, restrictions, limitations or other provisions contained in any law or any other ordinance.

Sec. 9-54. Impact Aid Payment or Administrative Fee. The City shall require an impact aid payment or administrative fee each time that bonds are issued under the provisions of this Article in order to enable the City to defray, in whole or in part, costs associated with the development, administration and expansion occasioned by the project. The impact aid payment or administrative fee shall be one percent (1%) of the principal amount of the bonds then being issued. The impact aid payment or administrative fee shall not constitute a part of the revenues and receipts of a project or derived from a project.

Sec. 9-55. Contract with Bondholders. The provisions of (i) this Article; (ii) the resolution of the Council authorizing the issuance of the bonds; (iii) the contract of sale of the bonds; (iv) any indenture of trust executed in connection therewith; and (v) the bonds shall collectively constitute a contract with the holder or holders of the bonds, and no subsequent change in this Article or in any law may in any way limit the rights of the holder or holders of the bonds or alter the obligations of the City under the terms of such contract until the entire principal of and interest and redemption premiums, if any, on such bonds have been fully paid or provision for the payment thereof made in accordance with the terms of such contract.

Sec. 9-56. Severability Clause. The provisions of this Article, except Section 9-51 hereof, are severable and if any such provisions or any sentence, clause or paragraph thereof shall be held

unconstitutional or ineffective by any court of competent jurisdiction, the decision of such court shall not affect or impair any of such remaining provisions.

Section 2. Sections 9-1 through 9-39, inclusive, of Chapter 9 of the Valdez City Code shall be designated: Article I. In General.

Section 3. Effective Date. The provisions of this Ordinance shall take effect immediately.

PASSED AND APPROVED by the Council of the City of Valdez, Alaska, on the 19th day of November, 1979.

Bill Walker
Mayor

ATTEST:

City Clerk /City Manager

First Reading: November 12, 1979
Second Reading: November 19, 1979
Adoption: November 19, 1979
Ayes: 6
Noes: 0
Absent: 1

APPROVED AS TO FORM:

HUGHES, THORSNESS, GANTZ, POWELL AND BRUNDIN
Attorneys for the City of Valdez

By Kenneth P. Jacobus
Kenneth P. Jacobus

CITY OF VALDEZ

ALASKA

RESOLUTION NO. 7953

A RESOLUTION RELATING TO THE FINANCING OF CERTAIN ECONOMIC DEVELOPMENT FACILITIES AND OTHER FACILITIES FOR GENERAL PUBLIC USE.

WHEREAS, the City of Valdez, Alaska (the "City") is authorized to issue economic development bonds pursuant to Article II of Chapter 9 of the City Code; and

WHEREAS, The Alpetco Company (the "Company"), a joint venture partnership organized or to be organized among Alaska Petrochemical Company, Charter Oil (Alaska) Inc. and The E. F. Hutton Group, Inc., desires to borrow funds made available through the issuance of such bonds in order to acquire, construct and develop certain economic development facilities and other facilities for general public use (the "Project") more fully described in Exhibit A attached hereto; and

WHEREAS, Federal Income Tax Regulations require that the City adopt a bond resolution with respect to such bonds or take some other similar official action toward the issuance of such bonds prior to the commencement of construction or acquisition of the Project; and

WHEREAS, the City considers the acquisition, construction and development of the Project to be in furtherance of its needs and public purposes and that the financing of the Project will have the effect of increasing employment, increasing the tax base in the City and promoting the general health and welfare of the inhabitants of the City

and that it is in the best interests of the City to issue such bonds in order to loan the proceeds to the Company; and

WHEREAS, the construction of the dock facility is consistent with and promotes the development of the Port of Valdez within the jurisdiction of the City as a major public port in Southcentral Alaska and as a gateway to Fairbanks and Interior Alaska; and

WHEREAS, the Project (except for the dock facility) will be located in an industrial park to be developed by the City for building sites for enterprises engaged in industrial, distribution or wholesale business and it is the intention of the City to proceed with the planning, development and construction of said industrial park;

NOW, THEREFORE, BE IT RESOLVED BY THE COUNCIL OF THE CITY OF VALDEZ, ALASKA, AS FOLLOWS:

1. The City will issue and sell its economic development bonds in one or more issues (the "Bonds") in a principal amount sufficient to provide funds to the Company in order to pay the cost as defined in Section 9-40 of the City Code of financing the Project, together with costs incident to the authorization, sale and issuance of the Bonds, the total of all such Project and incidental costs to be financed through the issuance of the Bonds being presently estimated to be $600,000,000.

2. The City will also issue and sell additional bonds in a principal amount sufficient to provide funds to the Company in order to pay any cost overruns or additional costs of the Project in excess of

the presently estimated costs, or the costs of any modifications or additions to the Project.

3. The proceeds of the Bonds will be loaned or otherwise provided to the Company in order to acquire, construct and develop the Project or any modifications or additions thereto.

4. The Mayor is hereby authorized and directed to execute and deliver a commitment letter to the Company substantially in the form provided in Exhibit B attached hereto.

5. The City will enter into a loan agreement or other financing agreement with the Company or other owners, lessees, users or beneficiaries of the Project to provide revenues to the City sufficient for the payment of the Bonds.

6. The City will adopt such proceedings and authorize the execution and delivery of such documents as may be necessary or advisable for the authorization, issuance and sale of the Bonds, the acquisition, construction and development of the Project, and the execution of a loan agreement or other financing agreement with respect to the Project with the Company or other owners, lessees, users or beneficiaries of the Project. The terms of the Bonds, including the rates of interest thereon shall be determined by the Council as set forth in Section 9-44 of the City Code.

7. The City will take or cause to be taken such other acts and adopt such further proceedings as may be required to implement the aforesaid undertakings or as it may deem appropriate in pursuance thereof.

8. The Bonds shall specify on their face that they shall be payable solely out of the revenues derived from the loan agreement or other financing agreement with respect to the Project and that they shall not constitute a debt or indebtedness of the City within the meaning of any provision or limitation of the Constitution or statutes of the State of Alaska.

9. The City shall develop a plan for an industrial park which shall be created upon submission and approval of the plan by the Council. Such industrial park shall be open for use as building sites by enterprises engaged in industrial, distribution or wholesale business including the Project.

10. It is intended that this Resolution shall constitute "some other similar official action" toward the issuance of the Bonds within the meaning of Section 1.103-8(a)(5) of the Federal Income Tax Regulations.

PASSED AND ADOPTED by the City Council of the City of Valdez, Alaska, this 19th day of November, 1979.

Bill Walker
Mayor

ATTEST:

City Clerk/City Manager

EXHIBIT A

TO RESOLUTION NO. 7953, ADOPTED NOVEMBER 19, 1979 BY THE COUNCIL OF THE CITY OF VALDEZ, ALASKA

DESCRIPTION OF PROJECT

The facilities comprising the Project to be acquired, constructed and developed within the city limits of Valdez, Alaska, include:

A dock facility for the loading and unloading of petroleum products and the associated piping and incidental facilities, storage facilities associated with the dock, general site development incidental to the preparation of the site as an industrial park (said industrial park to be used for building sites for industrial, distribution and wholesale businesses including the Project), air and water pollution control facilities, sewage and solid waste disposal facilities, facilities for the generation of electric energy for general use within the industrial park and by the general public; all to be used in connection with a petroleum refinery facility to be acquired, constructed and developed in conformity with the specifications of the Alaska Royalty Crude Oil Contract dated February 22, 1978 between Alaska Petrochemical Company and the State of Alaska, as heretofore and hereafter amended, and such other portions of the refinery facility as may be financed with economic development bonds, the interest on which is exempt from federal income taxation.

City of Valdez
Inc. 1901

OFFICE OF ADMINISTRATION
November , 1979

The Alpetco Company
c/o Alaska Petrochemical
Company
3700 Buffalo Speedway
Houston, Texas 77098

Gentlemen:

On behalf of the City of Valdez, Alaska (the "City"), I am pleased to confirm the City's commitment to loan or otherwise provide up to $600,000,000 or such additional amount as shall be deemed necessary to The Alpetco Company (the "Company") from the proceeds of the sale of the City's economic development bonds (the "Bond") in accordance with the provisions of Ordinance No. 7917 of the City (the "Ordinance") adopted on November 19, 1979, on the terms and subject to the conditions set forth below.

This commitment is subject to (i) entering into a loan agreement or other financing agreement with the Company in accordance with Resolution No. 7953 of the City adopted on November 19, 1979, and (ii) receipt of an opinion of bond counsel to the effect that the Bonds will be in conformity with the Ordinance and that interest thereon will be exempt under the existing statutes, regulations, court decisions and rulings from Federal income taxes.

All funds provided shall be expended in the acquisition, construction and development of the project facilities described in Exhibit A of the Resolution and for no other purpose. All funds provided shall be expended at such times and for such purposes as shall comply with the provisions of the Ordinance and shall preserve the tax-exempt nature of interest payable on the Bonds.

All expenses incurred by the City in connection with the preparation of the loan agreement or other financing agreement and the issuance of the Bonds, including fees of the City's counsel, bond counsel, financial advisory fees, administrative fees, printing and other expenses, will be paid out of the proceeds from the sale of the Bonds or by the Company.

AGO 560001

This commitment shall remain in effect for a period of 60 months from the date hereof. The Company shall not be obligated to pay a commitment fee in connection with this transaction, nor shall it be obligated to take down the full amount of the amount committed or any part thereof.

Sincerely,

CITY OF VALDEZ, ALASKA

By Bill Walker
Mayor

E F Hutton & Company Inc
New York Stock Exchange

E F Hutton

One Battery Park Plaza
New York, New York 10004
Telephone (212) 742-5000

November 19, 1979

The Honorable Bill Walker
Mayor
City Hall
Valdez, Alaska 99686

Dear Mayor Walker:

E. F. Hutton & Company Inc. ("E. F. Hutton") is pleased to confirm its commitment to purchase from the City of Valdez, Alaska (the "Issuer"), on the terms and conditions set forth in this letter, certain issues of economic development bonds (the "Bonds") aggregating up to $600,000,000, the proceeds of which are to be loaned or otherwise provided to The Alpetco Company (the "Company") in connection with the acquisition, construction and development of that portion of a petroleum refinery to be located in Valdez, Alaska, which may be financed with tax-exempt bonds.

E. F. Hutton will undertake to form an underwriting syndicate for the purpose of reoffering the Bonds to the general public or institutional investors. The price at which each issue of the Bonds will be purchased from you, the price at which they will be reoffered, the respective maturities and the other material terms of the Bonds will be fixed and agreed upon between E. F. Hutton and the Company at such time as the Bonds are available for re-offering. All material terms of the indenture of trust, the loan agreement or other financing agreement and any other security arrangements relating to the Bonds will be subject to the approval of the City.

Prior to the purchase of any issue of the Bonds, the Company in cooperation with the City must provide E. F. Hutton with an official statement for the reoffering of

the Bonds, and all other necessary information and materials as may be necessary for use therein in order that the official statement will fairly state the material facts relating to the offer and sale of the Bonds and relating to the description of the Company, including financial statements and other matters as may be required.

The obligations of E. F. Hutton shall be subject to the due performance of the following conditions:

(1) Receipt of an unqualified and approving legal opinion of bond counsel;

(2) Receipt of a legal opinion in a form satisfactory to E. F. Hutton from counsel to the Company as to the Company's participation in the transactions relating to the issuance of the Bonds;

(3) Receipt of a legal opinion of counsel for the underwriters approving the underlying documents and offering materials and compliance with applicable rules and regulations of the Securities and Exchange Commission;

(4) Receipt of all documents as may be reasonably required by E. F. Hutton or its counsel to evidence that the obligations undertaken by the Company are legal, valid and binding obligations;

(5) Receipt from Standard & Poor's Corporation of an investment grade rating on the Bonds;

(6) Receipt of such other certificates and documents as are customarily delivered in connection with an offering of industrial development bonds in the State of Alaska; and

(7) Agreement by the Company to maturity schedules, interest rates and other terms which are commercially reasonable given all of the facts and circumstances prevailing at the time the Bonds are available for reoffering.

E. F. Hutton shall have the right to cancel its obligation to purchase the Bonds prior to the closing of any of such issues if (1) any event shall have occurred which

would adversely affect the business or earnings of the Company or the feasibility of the Project; (2) any event shall have occurred which in the opinion of counsel to E. F. Hutton makes untrue or misleading in any material respect the statements in the official statement; (3) there shall have occurred any national calamity or any conflict involving the armed forces of the United States of America of such a magnitude as to markedly adversely affect the ability of the Underwriter to reoffer the Bonds; (4) there shall have been entered a stop order, ruling or regulation by the Securities and Exchange Commission or other Federal or state governmental agency making the sale of the Bonds or any similar class of securities a violation of law; or (5) the Congress of the United States or the Internal Revenue Service or the Treasury Department shall have proposed or enacted any legislation or proposed or adopted any regulation which would adversely affect the tax-exempt status of the interest on the Bonds.

It is understood that all expenses in connection with the proposed transactions, including fees and expenses of the Company's counsel, bond counsel, your counsel; the cost and expenses of preparing and printing official statements and all necessary documents; blue sky fees and expenses, including the fees of blue sky counsel; and the fees of the investment rating agency, will be paid by the Company whether or not the proposed sales of the Bonds are completed.

Sincerely,

E. F. HUTTON & COMPANY INC.

W. James Lopp II
Executive Vice President

Partners of The Alpetco Company - $350,000,000.00

Charter Oil (Alaska), Inc., Alaska Petrochemical Company, and E. F. Hutton (Alaska) Inc. have given The Alpetco Company letters commiting to provide $350,000,000.00 in equity funds for payment of Total Project Costs, as follows:

Charter Oil (Alaska), Inc.	$245,000,000.00
Alaska Petrochemical Company	81,900,000.00
E. F. Hutton (Alaska) Inc.	23,100,000.00
	$350,000,000.00

In order to confirm the above companies' commitment to invest $350,000,000.00 in equity funds, the shareholders of each company have given letters to The Alpetco Company commiting to contribute such equity funds to The Alpetco Company.

The letters from Alpetco's partners and letters from the partners' shareholders follow.

Nworths

AKI 111 m

ST 25 m

Charter 509 m

EFH 163 m

CHARTER OIL (ALASKA), INC.
208 Laura Street
Jacksonville, Florida 32201
904/358-4395

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, Charter Oil (Alaska), Inc., is a 70.0% partner in The Alpetco Company ("Alpetco"). Alpetco, a joint venture partnership, was established as of October 1, 1979, by the undersigned, Alaska Petrochemical Company and E. F. Hutton (Alaska) Inc. (collectively, the "Partners") to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between Alaska Petrochemical Company and the State of Alaska.

The Partners have determined that in order to proceed with the petrochemical and refining project in Alaska ("The Alpetco Project") contemplated by the Royalty Oil Contract, and to assist Alpetco's compliance with Article 10.2(3)(d) of the Royalty Oil Contract, it would be desirable for the Partners to commit to each other to contribute a substantial minimum amount of equity to Alpetco.

Accordingly, in consideration of similar commitments being made on the date hereof by the other Partners to contribute, with the undersigned, as equity up to $350 million in the aggregate to Alpetco, the undersigned commits to make partnership contributions to Alpetco of up to $245 million in the aggregate solely for use in connection with The Alpetco Project as its pro rata share of funds requested by Alpetco by thirty days' prior written notice to all its Partners, provided each of the other Partners makes its similar contribution pro rata in accordance with its partnership interest. The commitment of the undersigned hereunder is subject to final approval by the undersigned of the definitive documents relative to the long-term loan of funds for The Alpetco Project and to the execution by December 18, 1980, of such documents by Alpetco and the lenders providing such funds.

The above commitment of the undersigned is made solely for the purpose of assisting Alpetco in satisfying the Commissioner of Natural Resources of the State of Alaska as to Alpetco's compliance with Article 10.2c(3)(d) of the Royalty Oil Contract.

Attached hereto are commitments by the sole shareholder of the undersigned in support of the above commitment.

Very truly yours,

CHARTER OIL (ALASKA), INC.

By _____

The Charter Company
208 Laura Street · Post Office Box 2017
Jacksonville, Florida 32231
Telephone 904-358-4111 · Telex 56-239

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, The Charter Company, is the 100% shareholder of Charter Oil (Alaska), Inc. which is a 70.0% partner in The Alpetco Company ("Alpetco"). Charter Oil (Alaska), Inc. has made certain commitments today to Alpetco to contribute to Alpetco as equity up to $245 million ("Charter Oil (Alaska), Inc.'s Equity Commitment") in furtherance of Alpetco's refinery and petrochemical project in Alaska ("The Alpetco Project").

In support of Charter Oil (Alaska), Inc.'s Equity Commitment, the undersigned commits to make investments in Charter Oil (Alaska), Inc., in the form of equity or loans, of up to $245 million in the aggregate solely as required in respect of Charter Oil (Alaska), Inc.'s Equity Commitment, as and when requested by Charter Oil (Alaska), Inc. by twenty days' prior written notice and subject to final approval by Charter Oil (Alaska), Inc. of definitive documents relating to the long-term loan of funds for The Alpetco Project and to the execution by December 18, 1980, of such documents by Alpetco and the lenders providing such funds.

The above commitment of the undersigned is made solely for the purpose of supporting Charter Oil (Alaska), Inc.'s Equity Commitment, and is not intended for the benefit of any person other than Charter Oil (Alaska), Inc. in respect of Charter Oil (Alaska), Inc.'s Equity Commitment.

Yours very truly,

THE CHARTER COMPANY

By _____

ALASKA PETROCHEMICAL COMPANY
3700 BUFFALO SPEEDWAY
HOUSTON, TEXAS 77098
TELEPHONE 713 840-1243 TELEX 79146

December 13, 1979

The Alpetco Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, Alaska Petrochemical Company, is a 23.4% partner in The Alpetco Company ("Alpetco"). Alpetco, a joint venture partnership, was established as of October 1, 1979, by the undersigned, Charter Oil (Alaska), Inc. and E. F. Hutton (Alaska) Inc. (collectively, the "Partners") to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between Alaska Petrochemical Company and the State of Alaska.

The Partners have determined that in order to proceed with the petrochemical and refining project in Alaska ("The Alpetco Project") contemplated by the Royalty Oil Contract, and to assist Alpetco's compliance with Article 10.2(3)(d) of the Royalty Oil Contract, it would be desirable for the Partners to commit to each other to contribute a substantial minimum amount of equity to Alpetco.

Accordingly, in consideration of similar commitments being made on the date hereof by the other Partners to contribute, with the undersigned, as equity up to $350 million in the aggregate to Alpetco, the undersigned commits to make partnership contributions to Alpetco of up to $81.9 million in the aggregate solely for use in connection with The Alpetco Project as its pro rata share of funds requested by Alpetco by thirty days' prior written notice to all its Partners, provided each of the other Partners makes its similar contribution pro rata in accordance with its partnership interest. The commitment of the undersigned hereunder is subject to final approval by the undersigned of the definitive documents relative to the long-term loan of funds for The Alpetco Project and to the execution by December 18, 1980, of such documents by Alpetco and the lenders providing such funds.

AGO 560010

The above commitment of the undersigned is made solely for the purpose of assisting Alpetco in satisfying the Commissioner of Natural Resources of the State of Alaska as to Alpetco's compliance with Article 10.2c(3)(d) of the Royalty Oil Contract.

Attached hereto are commitments by the principal shareholders of the undersigned in support of the above commitment.

Very truly yours,

ALASKA PETROCHEMICAL COMPANY

By Gordon A Cain

ALASKA INTERSTATE COMPANY
P. O. Box 6554
HOUSTON, TEXAS 77005

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, Alaska Interstate Company, is a 75.45% shareholder of Alaska Petrochemical Company which is a 23.4% partner in The Alpetco Company ("Alpetco"). Alaska Petrochemical Company has made certain commitments today to Alpetco to contribute to Alpetco as equity up to $81.9 million ("Alaska Petrochemical Company's Equity Commitment") in furtherance of Alpetco's refinery and petrochemical project in Alaska ("The Alpetco Project").

In support of Alaska Petrochemical Company's Equity Commitment, the undersigned commits to make investments in Alaska Petrochemical Company, in the form of equity or loans, of up to $62,500,000 in the aggregate solely as required in respect of Alaska Petrochemical Company's Equity Commitment, as and when requested by Alaska Petrochemical Company by twenty days' prior written notice and subject to final approval by Alaska Petrochemical Company of definitive documents relating to the long-term loan of funds for The Alpetco Project and to the execution by December 18, 1980, of such documents by Alpetco and the lenders providing such funds.

The above commitment of the undersigned is made solely for the purpose of supporting Alaska Petrochemical Company's Equity Commitment, and is not intended for the benefit of any person other than Alaska Petrochemical Company in respect of Alaska Petrochemical Company's Equity Commitment.

Yours very truly,

ALASKA INTERSTATE COMPANY

By O. Charles Honig

Seatrain Lines, Inc.

Howard M. Pack
Vice Chairman of the Board

1 Chase Manhattan Plaza
New York, New York 10005

Phone: (212) 964-3400
Telex:
International: 232740 (RCA)
421225 (ITT)
Domestic: 710-581-2934 (TWX)
127-396 (WU)
Cables: SHIPTRAMP or OSTCORPO

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, Seatrain Lines, Inc. is the 100% shareholder of Barbour Oil Company, which is a 22.12% shareholder of Alaska Petrochemical Company which is a 23.4% partner in the Alpetco Company ("Alpetco"). Alaska Petrochemical Company has made certain commitments today to Alpetco to contribute to Alpetco as equity up to $81.9 million ("Alaska Petrochemical Company's Equity Commitment") in furtherance of Alpetco's refinery and petrochemical project in Alaska ("The Alpetco Project").

In support of Alaska Petrochemical Company's Equity Commitment, the undersigned commits to make investments in Alaska Petrochemical Company, in the form of equity or loans, of up to $19,500,000 in the aggregate solely as required in respect of Alaska Petrochemical Company's Equity Commitment, as and when requested by Alaska Petrochemical Company by twenty days' prior written notice and subject to final approval by Alaska Petrochemical Company of definitive documents relating to the long-term loan of funds for the Alpetco Project and to the execution by December 18,1980, of such documents by Alpetco and the lenders providing such funds.

The above commitment of the undersigned is made solely for the purpose of supporting Alaska Petrochemical Company's Equity Commitment, and is not intended for the benefit of any person other than Alaska Petrochemical Company in respect of Alaska Petrochemical Company's Equity Commitment.

Yours very truly,

SEATRAIN LINES, INC.

By _____

AGO 560013

E. F. Hutton (Alaska) Inc.
One Battery Park Plaza
New York, NY 10004
212/742-5005

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, E. F. Hutton (Alaska) Inc., is a 6.6% partner in The Alpetco Company ("Alpetco"). Alpetco, a joint venture partnership, was established as of October 1, 1979, by the undersigned, Alaska Petrochemical Company and Charter Oil (Alaska), Inc. (collectively, the "Partners") to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between Alaska Petrochemical Company and the State of Alaska.

The Partners have determined that in order to proceed with the petrochemical and refining project in Alaska ("The Alpetco Project") contemplated by the Royalty Oil Contract, and to assist Alpetco's compliance with Article 10.2(3) (d) of the Royalty Oil Contract, it would be desirable for the Partners to commit to each other to contribute a substantial minimum amount of equity to Alpetco.

Accordingly, in consideration of similar commitments being made on the date hereof by the other Partners to contribute, with the undersigned, as equity up to $350 million in the aggregate to Alpetco, the undersigned commits to make partnership contributions to Alpetco of up to $23.1 million in the aggregate solely for use in connection with The Alpetco Project as its pro rata share of funds requested by Alpetco by thirty days' prior written notice

EF Hutton

One Battery Park Plaza
New York, N.Y. 10004
Telephone (212) 742-5000

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, The E.F. Hutton Group Inc., is the 100% shareholder of E.F. Hutton (Alaska) Inc. which is a 6.6% partner in The Alpetco Company ("Alpetco"). E.F. Hutton (Alaska) Inc. has made certain commitments today to Alpetco to contribute to Alpetco as equity up to $23.1 million ("E.F. Hutton (Alaska) Inc.'s Equity Commitment") in furtherance of Alpetco's refinery and petrochemical project in Alaska ("The Alpetco Project").

In support of E.F. Hutton (Alaska) Inc.'s Equity Commitment, the undersigned commits to make investments in E.F. Hutton (Alaska) Inc., in the form of equity or loans, of up to $23.1 million in the aggregate solely as required in respect of E.F. Hutton (Alaska) Inc.'s Equity Commitment, as and when requested by E.F. Hutton (Alaska) Inc. by twenty days' prior written notice and subject to final approval by the undersigned of definitive documents relating to the long-term loan of funds for The Alpetco Project and to the execution by December 18, 1980, of such documents by Alpetco and the lenders providing such funds.

The above commitment of the undersigned is made solely for the purpose of supporting E.F. Hutton (Alaska) Inc.'s Equity Commitment and is not intended for the benefit of any person other than E.F. Hutton (Alaska) Inc. in respect of E.F. Hutton (Alaska) Inc.'s Equity Commitment.

Yours very truly,

THE E.F. HUTTON GROUP INC.

By _____

to all its Partners, provided each of the other Partners makes its similar contribution pro rata in accordance with its partnership interest. The commitment of the undersigned hereunder is subject to final approval by the undersigned of the definitive documents relative to the long-term loan of funds for The Alpetco Project and to the execution by December 18, 1980, of such documents by Alpetco and the lenders providing such funds.

The above commitment of the undersigned is made solely for the purpose of assisting Alpetco in satisfying the Commissioner of Natural Resources of the State of Alaska as to Alpetco's compliance with Article 10.2c(3)(d) of the Royalty Oil Contract.

Attached hereto are commitments by the sole shareholder of the undersigned in support of the above commitment.

Very truly yours,

E. F. HUTTON (ALASKA) INC.

By _____

Article 10.2(3)(e)

"Obtain a commitment or commitments for interim financing for the construction of the petrochemical facility."

Chemical Bank (New York) and Manufacturers Hanover Trust Company have been named co-agent banks to provide a line of credit for payment of interim construction costs of non-tax exempt financed costs of the project. Alpetco's financial projections and funding schedule (attached Exhibit e-1) indicates that the maximum line of construction financing needed is $ 92,500,000.00. The banks' commitment letters, totaling $150,000,000.00, are attached.

In addition to the above $150,000,000.00, up to $600,000,000.00 in interim funds for construction costs for items qualifying for tax exempt financing will be provided by serialized take-down of the tax exempt bonds. A letter from Kutak, Rock & Huie, underwriter's counsel, explaining this procedure, is enclosed.

While we have provided for interim financing if needed, it is possible that the partners will determine to contribute the total equity required during the early months of construction, thus eliminating the need for interim construction financing. A funding schedule indicating this possibility is attached as Exhibit e-2.

We believe we have fully complied with this benchmark requirement.

work less than anticipated

CHEMICAL BANK

Energy & Minerals Division
277 Park Avenue, New York, NY 10017. Tel (212) 922-6936

Everett M. Schenk
Vice President

December 11, 1979

The ALPETCO Company
3700 Buffalo Speedway
Suite 806
Houston, TX 77096

Dear Sirs:

During recent discussions with representatives of the owners of The ALPETCO Company ("ALPETCO"), ALPETCO requested that Chemical Bank and Manufacturers Hanover Trust Company ("the Banks") submit a letter or letters to ALPETCO outlining each Bank's commitment to lend up to $75 million in interim construction funds to ALPETCO in connection with ALPETCO's proposed plans to build a petrochemical and oil refining complex in Valdez, Alaska.

With reference to these discussions, we are pleased to confirm that we will participate in the amount of $75 million in such a $150 million facility, subject to our satisfaction with the following items:

1. Our review of the economic projections and the underlying assumptions which demonstrate the viability of the project.

2. The availability of guarantees and undertakings from various parties covering completion of the project, construction of the project, and cost overruns which may occur during the life of the project.

3. The continuance in effect of the Alaska Royalty Crude Oil Contract; the continued fulfillment in accordance with their terms of all agreements and obligations of the parties contained therein; and assurance that the Alaska petroleum reserves available to ALPETCO under the Contract are adequate to support all project financing.

4. The final written form of the ALPETCO joint venture agreement among E. F. Hutton (Alaska) Inc., Alaska Petrochemical Company and Charter Oil (Alaska) Inc.

5. The availability to ALPETCO of sufficient equity to complete the project as presently contemplated, whether through the sale of royalty crude oil or otherwise.

6. Sufficient collateral and undertakings as may be necessary to assure repayment of the construction loans.

7. The availability from responsible lenders or permanent financing sufficient to provide a complete "take-out" for the interim bank construction financing.

8. The commitment of Manufacturers Hanover Trust Company to become a party to the bank credit facility pursuant to which it will make available an amount equal to the amount to be provided by this bank.

The foregoing financing is, of course, subject to our satisfaction with the above requirements and with any other matters that may become relevant from a banking point of view and, by December 18, 1980, our entering into with you a definitive credit agreement containing such terms (including a satisfactory interest rate) and such representations and warranties, conditions, covenants, and events of default and other provisions as may be relevant in the circumstances.

If we may be of further assistance to you in this matter, please do not hesitate to call me.

Sincerely,

Everett M. Schenk

Everett M. Schenk
Vice President

MANUFACTURERS HANOVER TRUST COMPANY

350 PARK AVENUE, NEW YORK, N. Y. 10022

December 10, 1979

The ALPETCO Company
3700 Buffalo Speedway
Suite 806
Houston, TX 77096

Dear Sirs:

During recent discussions with representatives of the owners of The ALPETCO Company ("ALPETCO"), ALPETCO requested that Chemical Bank and Manufacturers Hanover Trust Company ("the Banks") submit a letter or letters to ALPETCO outlining each Bank's commitment to lend up to $75 million in interim construction funds to ALPETCO in connection with ALPETCO's proposed plans to build a petrochemical and oil refining complex in Valdez, Alaska.

With reference to these discussions, we are pleased to confirm that we will participate in the amount of $75 million in such a $150 million facility, subject to our satisfaction with the following items:

1. Our review of the economic projections and the underlying assumptions which demonstrate the viability of the project.

2. The availability of guarantees and undertakings from various parties covering completion of the project, construction of the project, and cost overruns which may occur during the life of the project.

3. The continuance in effect of the Alaska Royalty Crude Oil Contract; the continued fulfillment in accordance with their terms of all agreements and obligations of the parties contained therein; and assurance that the Alaska petroleum reserves available to ALPETCO under the Contract are adequate to support all project financing.

4. The final written form of the ALPETCO joint venture agreement among E.F. Hutton (Alaska) Inc., Alaska Petrochemical Company and Charter Oil (Alaska) Inc.

5. The availability to ALPETCO of sufficient equity to complete the project as presently contemplated, whether through the sale of royalty crude oil or otherwise.

6. Sufficient collateral and undertakings as may be necessary to assure repayment of the construction loans.

7. The availability from responsible lenders of permanent financing sufficient to provide a complete "take-out" for the interim bank construction financing.

8. The commitment of Chemical Bank to become a party to the bank credit facility pursuant to which it will make available an amount equal to the amount to be provided by this bank.

The foregoing financing is, of course, subject to our satisfaction with the above requirements and with any other matters that may become relevant from a banking point of view and, by December 18, 1980, our entering into with you a definitive credit agreement containing such terms (including a satisfactory interest rate) and such representations and warranties, conditions, covenants and events of default and other provisions as may be relevant in the circumstances.

Sincerely,

William H. Hastings Jr.
Assistant Vice President

KUTAK ROCK & HUIE
THE OMAHA BUILDING
1650 FARNAM STREET
OMAHA, NEBRASKA 68102
(402) 346-6000

ROBERT J. KUTAK
HAROLD L. ROCK
WILLIAM G. CAMPBELL
ALLAN JAY GARFINKLE
THOMAS A. WOODWARD
GLEN A. BURBRIDGE
RI[illegible]D L. WEILL
JI[illegible]. HUSSELMAN
WA[illegible]CE H. JOHNSON
RICHARD A. SPELLMAN
STEVEN S. HUFF
GREGORY DuBOIS ERWIN
THOMAS J. McCUSKER
GEORGE H. KRAUSS
MAUREEN E. McGRATH
HUGH W. McNULTY, JR.
KENNETH J. STUART
DIRK W. deROOS
ANGELO P. PARKER
J. MICHAEL GOTTSCHALK
KEN[illegible]TH E. ILTZ
JAMES D. ARUNDEL
JOHN J. WAGNER
DONALD [illegible]. KRESS
DANIEL S. HOROWITZ
PAUL R. TI[illegible]FT
RONALD T. PFEIFER
GREGORY W. SEARSON
JOHN E. HUBBARD
HARRY D. DIXON, JR.
JOE E. ARMSTRONG
WILLIAM E. HOLLAND
RICHARD D. CIMINO
GARETH G. MORRIS
HAVEN N. B. PELL
PAUL D. BUDD
JOEL T. BOEHM
TERRENCE J. FERGUSON
C. GREGORY H. EDEN
LARRY L. CARLILE
SARAH J. PENN
LAUREN M. RONALD
PATRICIA J. WINTER
LINDSEY MILLER LERMAN
JOYCE A. DIXON
DIANNE L. STODDARD
TIMOTHY J. KINCAID
JOHN C. MINAHAN, JR.
FRED M. GREGURAS
PAUL E. BELITZ
DENIS P. BURKE
SCOTT C. HOYT
DANIEL S. REYNOLDS
DAVID A. JACOBSON
P. THOMAS POGGE
J. THOMAS MARTEN
D. CHARLES SHOEMAKER
KENNETH R. DODDS
WALTER L. GRIFFITHS
THOMAS B. HOLLEY
JO E. BASS
FRANK A. TAYLOR
RANDALL R. ELEY
CURTIS L. CHRISTENSEN
MICHAEL L. CURRY
LOREN E. DESSONVILLE
DAWN R. DUVEN
JANE ERDENBERGER
FELICIA O. FLOWERS
LYNNE A. FRIEDEWALD
DENNIS L. HOLSAPPLE
FRANK M. SCHEPERS
JULIA G. GINSBURG
CLIFTON R. JESSUP, JR.
DAVID A. GARDELS
CHRISTIAN I. HALABI
JEDD S. PALMER
SHEILA A. PHILLIPS
MOLLY M. ROMERO
PATRICIA K. SCHUETT
STEVEN W. SELINE
JUDY A. WEILL
DENNIS B. WILSON

ROMAN L. HRUSKA
WILLIAM GRODINSKY
FRANK L. BURBRIDGE
GAIL E. BURBRIDGE
COUNSEL

ATLANTA
1200 STANDARD FEDERAL SAVINGS BUILDING
ATLANTA, GEORGIA 30303
(404) 522-8700

DENVER
1330 COLORADO NATIONAL BUILDING
DENVER, COLORADO 80202
(303) 534-1330

MINNESOTA
4644 IDS TOWER
MINNEAPOLIS, MINNESOTA 55402
(612) 338-1460

WASHINGTON
1101 CONNECTICUT AVENUE, N. W.
WASHINGTON, D. C. 20036
(202) 828-2400

December 11, 1979

Mr. Gordon A. Cain
President
The Alpetco Company
c/o Alaska Petrochemical
Company
Suite 806
3700 Buffalo Speedway
Houston, Texas 77098

Re: The Proposed Tax-Exempt Financing
for the Alpetco Refinery

Dear Mr. Cain:

We have been asked to comment on the use of tax-exempt bond proceeds to finance a portion of the construction costs of Alpetco's proposed refinery and related facilities at Valdez, Alaska.

In a tax-exempt financing such as the one under consideration, bond proceeds are available to pay construction costs, which eliminates the need for interim bank financing during the construction period. The indenture pursuant to which the bonds are issued will permit the periodic takedown of bond proceeds to pay construction costs as they are incurred.

In the current economic climate, the use of bond proceeds to pay construction costs as they are incurred is preferable to an interim financing of such costs with a bank loan followed by a long-term tax-exempt bond financing. The prime rate for conventional corporate borrowings is now 15 1/4% while the interest rate on long-term tax-exempt bond issues similar to the one proposed by Alpetco is in the range of 8 1/2%.

Moreover, federal tax law permits unexpended moneys in the construction fund established with tax-exempt bond proceeds to be invested in taxable obligations at whatever yield is obtainable in the market.

Federal tax law does impose limitations on the earnings which may be legally derived from investment of tax-exempt bond proceeds. Those limitations are, however, subject to a number of exceptions. One exception relates to temporary periods during which bond proceeds are held pending their use in a construction project. If certain tests relating to the availability of a temporary period are met, bond proceeds can be invested during the period without limitation as to permissible earnings.

The maximum temporary period is generally three years, but may be as long as five years if an independent engineer certifies that a period longer than three years is necessary for construction and explains the reasons for it.

The requirements for the availability of a temporary period are that there be a binding obligation incurred within six months after the issuance of the bonds to expend at least $100,000 on the project, that at least 85% of the proceeds of the bond issue be reasonably expected to be expended during the temporary period, and that the project proceed with due diligence to completion.

Not only is there no limitation on the amount by which the yield on a temporary period investment may exceed the yield on the bonds, there is also no limitation on the duration of an investment maturing during the temporary period

other than the availability of funds to pay for construction as it progresses under the due diligence requirement. Assume, for example, a $600 million bond issue for a four year construction period, with $100 million to be expended in the first year, $125 million in the second year, $150 million in the third year and $225 million in the fourth year. If the investment of the $225 million to be expended in the fourth year will produce a higher yield through investment in securities with a term of three years rather than through investment in shorter term securities, such an investment may be made.

The use of bond proceeds to pay construction costs, which avoids the need for interim construction financing, is a conventional technique in tax-exempt financings. From the foregoing discussion, it is apparent that the present yield curve and the permissibility of unrestricted investment earnings during the construction temporary period make such use desirable for the Alpetco project.

Sincerely,

Robert J. Kutak

ljm

AGO 560025

Exhibit 1

THE ALPETCO COMPANY

December 13, 1979

Pro Forma Funds Flow Statement
($Millions)

Sources	1977 to 3rd Qtr. 1979	1979 4th Qtr.	1980 1st	1980 2nd	1980 3rd	1980 4th	1981 1st	1981 2nd	1981 3rd	1981 4th	1982 1st	1982 2nd	1982 3rd	1982 4th	Total
Equity:															
Charter Oil (Alaska), Inc.	-0-	5.0	6.0	60.2	13.5	-0-	12.1	13.4	14.6	13.0	14.5	13.2	6.4	73.4	244.2
Alaska Petrochemical Company	7.0	-0-	-0-	17.0	4.5	-0-	4.0	4.5	4.9	4.4	4.8	14.4	2.2	24.5	81.5
E.F. Hutton (Alaska), Inc.	-0-	-0-	-0-	4.8	1.3	-0-	1.2	1.2	1.4	1.2	1.4	1.2	.6	6.9	23.0
Total Equity	7.0	5.0	6.0	82.0	19.3	-0-	17.3	19.1	20.9	18.6	20.7	18.8	9.2	104.8	348.7
Debt:															
Supplier Credits-Takedown[1]	-0-	-0-	-0-	-0-	-0-	-0-	43.5	78.1	86.1	87.6	88.8	92.5	88.6	170.5	735.7
Tax Exempt Bonds-Use[2]	-0-	-0-	-0-	-0-	-0-	-0-	68.2	75.4	76.9	78.6	92.0	89.0	92.8	-0-	572.9
Interim Financing-Takedown[3]	-0-	-0-	-0-	-0-	-0-	43.5	78.1	86.1	87.6	88.8	92.5	88.6	84.0	-0-	--
Interim Financing-Payback	-0-	-0-	-0-	-0-	-0-	-0-	(43.5)	(78.1)	(86.1)	(87.6)	(88.8)	(92.5)	(88.6)	(84.0)	--
Total Debt	-0-	-0-	-0-	-0-	-0-	43.5	146.3	161.5	164.5	167.4	184.6	177.5	176.8	86.5	1308.6
Total Sources	7.0	5.0	6.0	82.0	19.3	43.5	163.6	180.6	185.4	186.0	205.3	196.3	186.0	191.3	1657.3
Uses															
Development Cost	7.0	5.0	6.0	7.0	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	25.0
Construction Cost	-0-	-0-	-0-	75.0	18.3	39.1	154.4	168.2	171.1	166.1	177.8	163.8	149.1	149.1	1432.0
Interest Expense	-0-	-0-	-0-	-0-	-0-	2.6	3.5	6.0	7.5	12.1	13.5	18.0	21.9	26.3	111.4
Taxes & Insurance	-0-	-0-	-0-	-0-	1.0	1.0	2.0	2.7	3.1	4.0	4.5	5.0	5.5	6.5	35.4
Training & Misc.	-0-	-0-	-0-	-0-	-0-	.8	3.7	3.7	3.7	3.8	9.5	9.5	9.5	9.4	53.6
Total Uses	7.0	5.0	6.0	82.0	19.3	43.5	163.6	180.6	185.4	186.0	205.3	196.3	186.0	191.3	1657.3
Cumulative Totals	7.0	12.0	18.0	100.0	119.3	162.3	326.4	507.0	692.4	878.4	1083.7	1280.0	1466.0	1657.3	

(1) Takedown of supplier credits occurs on the first day of each quarter according to the amounts expended during the preceding quarter.

(2) Tax-exempt bonds are syndicated prior to December 10, 1980 and sold and drawn down in three equal amounts of $191.0 million each beginning January 1, 1981.

(3) Interim construction financing is used to bridge the takedown of supplier credits.

AGO 560026

Exhibit 2

December 12, 1979

THE ALPETCO COMPANY

Pro Forma Funds Flow Statement
($Millions)

Sources	1977 to 3rd Qtr,1979	1979 4th Qtr.	1980 1st	1980 2nd	1980 3rd	1980 4th	1981 1st	1981 2nd	1981 3rd	1981 4th	1982 1st	1982 2nd	1982 3rd	1982 4th	Total
Equity:															
Charter Oil (Alaska), Inc.	-0-	5.0	6.0	60.2	13.5	30.5	47.7	30.3	27.0	25.2	-0-	-0-	-0-	-0-	244.2
Alaska Petrochemical Company	7.0	-0-	-0-	17.0	4.5	10.2	15.9	10.1	9.0	8.4	-0-	-0-	-0-	-0-	81.5
E.F. Hutton (Alaska), Inc.	-0-	-0-	-0-	4.8	1.3	2.8	4.5	2.9	2.6	2.4	-0-	-0-	-0-	-0-	23.0
Total Equity	7.0	5.0	6.0	82.0	19.3	43.5	68.1	43.3	38.6	36.0	-0-	-0-	-0-	-0-	348.7
Debt:															
Supplier Credit-Takedown[1]	-0-	-0-	-0-	-0-	-0-	-0-	43.5	78.1	86.1	87.6	88.8	92.5	88.6	170.5	735.7
Tax Exempt Bonds-Use[2]	-0-	-0-	-0-	-0-	-0-	-0-	68.2	75.4	76.9	78.6	92.0	89.0	92.8	-0-	572.5
Interim Financing-Takedown[3]	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-
Interim Financing-Payback	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-
Total Debt	-0-	-0-	-0-	-0-	-0-	-0-	111.7	153.5	163.0	166.2	180.8	181.5	181.4	170.5	1308.6
Total Sources	7.0	5.0	6.0	82.0	19.3	43.5	179.8	196.8	201.6	202.2	180.1	181.5	181.4	170.5	1657.3
Uses															
Development Cost	7.0	5.0	6.0	7.0	-0-	41.7	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	25.0
Construction Cost	-0-	-0-	-0-	75.0	18.3	-0-	154.4	168.2	171.1	166.1	177.8	163.8	149.1	149.1	1432.0
Interest Expense	-0-	-0-	-0-	-0-	-0-	-0-	3.5	6.0	7.5	12.1	13.5	18.0	21.9	26.3	111.4
Taxes & Insurance	-0-	-0-	-0-	-0-	1.0	1.9	2.0	2.7	3.1	4.0	4.5	5.0	5.5	6.5	35.4
Training & Misc.	-0-	-0-	-0-	-0-	-0-	.8	3.7	3.7	3.7	3.8	9.5	9.5	9.5	9.4	53.6
Investment Account	-0-	-0-	-0-	-0-	-0-	-0-	16.2	16.2	16.2	16.2	(24.5)	(14.8)	(4.6)	(20.9)	-0-
Total Uses	7.0	5.0	6.0	82.0	19.3	43.5	179.8	196.8	201.6	202.2	180.0	181.5	181.4	170.5	1657.3
Cumulative Totals	7.0	12.0	18.0	100.0	119.3	162.3	342.1	538.9	740.5	942.7	1123.5	1305.0	1486.4	1657.3	

(1) Takedown of supplier credits occurs on the first day of each quarter according to the amounts expended during the preceding quarter.

(2) Tax-exempt bonds are syndicated prior to December 18, 1980 and sold and drawn down in three equal amounts of $191.0 million each beginning January 1, 1980.

(3) Interim construction financing is provided by early equity contributions as needed.

Article 10.2(3)(f)

"Complete and file an Environmental Impact Assessment on the petrochemical facility."

As stated in Commissioner LeResche's letter to Gordon Cain dated September 27, 1979 (enclosed herein under tab 10.2(3)(g):

> "Based upon the Notice of Intent, we conclude that Alpetco has complied with Section 10.2(3)(f) of the 'Agreement for the Sale and Purchase of State Royalty Oil' approved by Legislative Resolve No. 42 (CONTRACT)."

We submitted a letter to the Commissioner and Mr. Tom Cook, Director of Division of Minerals and Energy Management on November 19, 1979 stating that we believed the Commissioner's September 27 letter verified compliance with this benchmark requirement.

Although not required by any benchmarks, we are pleased to note that the Alpetco Environment Impact Statement has been completed and a copy was submitted to the Commissioner on December 5, 1979 and further that notice of the EIS was published in the Federal Register on December 7, 1979.

Article 10.2(3)(g)

"Complete and file all material state, local and Federal permit applications."

As stated in Commissioner LeResche's letter to Gordon Cain dated September 27, 1979 (enclosed under this tab):

> "Further we find that if Alpetco files all of the applications for permits as indicated in Attachment #1 by December 18, 1979, Alpetco will have complied with Section 10.2(3)(g) of the CONTRACT."

We submitted a letter to the Commissioner and Mr. Tom Cook, Director of Division of Minerals and Energy Management on November 19, 1979 which contained copies of all the permits filed by Alpetco pursuant to the list of permits included in Attachment #1 to the Commissioner's September 27, 1979 letter. In addition, we submitted the name of a contact at each governmental agency which could verify that the permits have been timely filed.

Having filed all permits as indicated by the Commissioner, we believe we have complied with this benchmark requirement.

ALASKA PETROCHEMICAL COMPANY
601 WEST 5TH AVENUE
ANCHORAGE, ALASKA 99501
TELEPHONE 907 272-1517 TELEX 090-25157

November 19, 1979

Mr. Robert E. LeResche, Commissioner
State of Alaska
Department of Natural Resources
Pouch M
Juneau, Alaska 99811

Mr. Tom Cook, Director
Division of Minerals and Energy Management
Department of Natural Resources
State of Alaska
703 W. Northern Lights Blvd.
Anchorage, Alaska 99503

Gentlemen:

This letter is submitted in response to Tom Cook's letter to me of October 21, 1979 and pursuant to Section 10.2 (3) (f) and (g) of the " Agreement for the Sale and Purchase of State Royalty Oil between Alaska Petrochemical Company and the State of Alaska, dated February 22, 1978" (The Agreement).

Section 10.2 (3)(f)

Enclosed (#1) is a copy of Commissioner LeResche's letter of September 27, 1979 to Gordon Cain concerning Section 10.2 (3)(f) of the Agreement. As stated in the September 27 letter, Alpetco's previous submittals and a review by the Commissioner of the Department of Environmental Conservation, an attorney designated by the Attorney General, and the permit coodinator have established that Alpetco has complied with Section 10.2 (3)(f) of The Agreement.

In addition, the United States Environmental Protection Agency's (EPA) "Notice of Availability" for a Draft Environmental Impact Statement will be announced in the Federal Register on Friday, December 7, 1979.

Section 10.2 (3)(g)

Attached to Commissioner LeResche's letter of September 27, 1979 to Gordon Cain was a list of all material state, federal, and local permit applications required to be filed by December 18,

1979 under Section 10.2 (3)(g). Enclosed (#2) with this letter are the cover or transmittal letters for each of the required permit applications or the appropriate state or federal agency's waiver or determination of inapplicability.

Verification of the filing for each of the applications required by Commissioner LeResche may be obtained from the appropriate agency. For your convenience, a list providing the name, mailing address, and telephone number of a contact person for each agency is enclosed (#3).

A separate transmittal is being made this date to Mr. Ed Park of the Division of Minerals and Energy Management. This transmittal includes a copy of this letter with enclosures and copies of all the permit applications required under Section 10.2 (3)(g). Copies of each of these permit application have been previously provided to Commissioner LeResche's office in Juneau.

If you have any further questions regarding Alpetco's performance under Section 10.2 (3)(f) and (g) of the Agreement, please direct them to:

Ronald R. Dagon, Manager
Environmental Programs and Permitting
ALASKA PETROCHEMICAL COMPANY
601 West 5th, Suite 320
Anchorage, Alaska 99501
(907) 272-1517

Sincerely yours,

ALASKA PETROCHEMICAL COMPANY

Willard M. Hanzlik
Vice-President

Enclosures: 3

cc: Mr. Ed Park (DMEM)
Ronald R. Dagon (Alpetco-Anchorage)

ENCLOSURE #1

Commissioner Robert E. LeResche letter to
Gordon A. Cain dated September 27, 1979
with Attachment #1

ATTACHMENT #1

PERMIT APPLICATIONS REQUIRED BY SECTION 10.2(3)(g) OF THE AGREEMENT FOR THE SALE AND PURCHASE OF STATE ROYALTY OIL APPROVED BY LEGISLATIVE RESOLVE NO. 42

STATE PERMITS

Department of Environmental Conservation Air Quality Control Permit to Operate.

Department of Environmental Conservation Discharge Into Navigable Waters Certificate of Reasonable Assurance.

Department of Environmental Conservation Solid Waste Disposal Permit.

Department of Environmental Conservation Waste Water Disposal Permit [required only if this permit is not waived pursuant to A.S. 46.03.110(e)].

Department of Natural Resources Pipeline Right-of-Way Permit.

Department of Natural Resources Tidelands Permit [required only if Alpetco will secure tidelands for the construction dock from the State].

Department of Natural Resources Water Use Permit.

FEDERAL PERMITS

U.S. Army Corps of Engineers' Structures Permit.

U.S. Department of Transportation Coast Guard Bridge Permit [required only if the Coast Guard determines that waters to be bridged are navigable; Alpetco is required to obtain the Coast Guard's determination].

U.S. Environmental Protection Agency National Pollutant Discharge Elimination System Permit.

AGO 560032

Ron Dagon ✓ M. B. Carmichael

RECEIVED
OCT 15 1979
ALPETCO

STATE OF ALASKA

JAY S. HAMMOND, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

OCT 22 1979

OFFICE OF THE COMMISSIONER / POUCH M — JUNEAU 99811

September 27, 1979

Mr. Gordon A. Cain
President
Alaska Petrochemical Company
3700 Buffalo Speedway
Suite 806
Houston, Texas 77098

Dear Mr. Cain:

On December 7, 1978, Region X of the U.S. Environmental Protection Agency (EPA) issued a Notice of Intent concerning the petrochemical facility to be constructed near Valdez, Alaska by Alaska Petrochemical Company (ALPETCO). The Notice of Intent sets forth EPA's conclusions based upon an initial assessment of the project. EPA has concluded that the proposed facility is a new source and that the issuance of a NPDES permit for the facility would be a major federal action requiring the preparation of an Environmental Impact Statement (EIS). ALPETCO has entered a Memorandum of Understanding with EPA which provides for the preparation of the EIS. It is my understanding that ALPETCO is currently intending to file for the federal, state, and local permits indicated in Attachment #1 to this letter by December 18, 1979.

The Notice of Intent and Attachment #1 have been reviewed by the Commissioner of the Department of Environmental Conservation, an attorney designated by the Attorney General, and the permit coordinator. Based upon the Notice of Intent, we conclude that ALPETCO has complied with Section 10.2(3)(f) of the "Agreement for the Sale and Purchase of State Royalty Oil" approved by Legislative Resolve No. 42 (CONTRACT).

10-J9LH

AGO 560033

Further, we find that if ALPETCO files all of the applications for permits as indicated in Attachment #1 by December 18, 1979, ALPETCO will have complied with Section 10.2(3)(g) of the CONTRACT. For convenient reference the pertinent sections of the CONTRACT are quoted below:

(f) Complete and file an Environmental Impact Assessment on the Petrochemical Facility.

(g) Complete and file all material state, local and federal permit applications.

Sincerely,

Robert E. LeResche
Commissioner

Attachment

List No. 1 - Federal Permits (Continued)

U.S. Environmental Protection Agency Permit for Treatment, Storage or Disposal of Hazardous Wastes [not required until such time as an application may be made pursuant to regulations promulgated by EPA pursuant to 42 U.S.C., §6925 and which are effective pursuant to 42 U.S.C., §6930(b)].

U.S. Environmental Protection Agency Prevention of Significant Deterioration Permit.

LOCAL PERMITS

Ground Lease from City of Valdez.

Tidelands Lease from the City [required only if Alpetco will secure tidelands for the construction dock from the City].

Enclosure #2

Cover or transmittal letters for each
required permit application or the
waiver or determination of inapplicability.

ATTACHMENT #1 LeResche to Cain (modified)

PERMIT APPLICATIONS REQUIRED BY SECTION 10.2(3)(g) OF THE AGREEMENT FOR THE SALE AND PURCHASE OF STATE ROYALTY OIL APPROVED BY LEGISLATIVE RESOLVE NO. 42	Date permit filed and/or waiver or determination received
STATE PERMITS	
Department of Environmental Conservation Air Quality Control Permit to Operate.	10/30/79
Department of Environmental Conservation Discharge Into Navigable Waters Certificate of Reasonable Assurance.	10/30/79
Department of Environmental Conservation Solid Waste Disposal Permit.	10/16/79
Department of Environmental Conservation Waste Water Disposal Permit [required only if this permit is not waived pursuant to A.S. 46.03.110(e)].	11/1/79
Department of Natural Resources Pipeline Right-of-Way Permit.	9/26/79
Department of Natural Resources Tidelands Permit [required only if Alpetco will secure tidelands for the construction dock from the State].	NA
Department of Natural Resources Water Use Permit.	9/26/79
FEDERAL PERMITS	
U.S. Army Corps of Engineers' Structures Permit.	9/20/79 and 9/21/79
U.S. Department of Transportation Coast Guard Bridge Permit [required only if the Coast Guard determines that waters to be bridged are navigable; Alpetco is required to obtain the Coast Guard's determination].	10/31/79
U.S. Environmental Protection Agency National Pollutant Discharge Elimination System Permit.	9/19/79 (update)

AGO 560037

List No. 1 - Federal Permits (Continued)

U.S. Environmental Protection Agency Permit for Treatment, Storage or Disposal of Hazardous Wastes [not required until such time as an application may be made pursuant to regulations promulgated by EPA pursuant to 42 U.S.C., §6925 and which are effective pursuant to 42 U.S.C., §6930(b)].	11/1/79
U.S. Environmental Protection Agency Prevention of Significant Deterioration Permit.	10/8/79

LOCAL PERMITS

Ground Lease from City of Valdez.	10/11/79 and 10/30/79
Tidelands Lease from the City [required only if Alpetco will secure tidelands for the construction dock from the City].	10/11/79

Article 10.2(3)(h)

"Complete plant design and optimization necessary to obtain a definitive project cost estimate ('definitive' meaning a cost estimate containing no more than fifteen percent (15%) variance in anticipated costs)."

In support of compliance with this benchmark, attached is a letter from Gordon Cain describing in general the work completed for plant design and optimization and reports discussing in more detail Plant Design and Optimization Studies. We are also submitting separately today eleven (11) bound volumes of engineering design, optimization studies and reports prepared for Alpetco by its engineers and process licensors and consultants. An index of these volumes follows Mr. Cain's letter. Two of the volumes, "Exxon Technology" and "Sulfur Recovery Facilities" are subject to secrecy agreements between Alpetco and the respective engineering companies and therefore are submitted with a request for confidential treatment.

This work has been underway for over eighteen months and represents design and optimization necessary to obtain a definitive project cost estimate.

Five of the volumes referred to above were prepared by The Lummus Company, former Managing Contractor for Alaska Petrochemical Company. In November, 1979, the partners of The Alpetco Company named C. F. Braun Company as Managing Engineers and Contractors for the petrochemical facility. C. F. Braun will assume the responsibilities previously assigned to Lummus.

We understand that The Pace Company, Houston, Texas has been retained by the Department of Natural Resources to review Alpetco's plant design and optimization and that the State's consultants will submit a report to the Commissioner by December 14, 1979 regarding Alpetco's compliance with this benchmark.

We believe that Alpetco is in full compliance with this benchmark requirement.

ALASKA PETROCHEMICAL COMPANY
3700 BUFFALO SPEEDWAY
HOUSTON, TEXAS 77098
TELEPHONE 713 840-1243 TELEX 791461

December 3, 1979

Dr. Robert E. LeResche, Commissioner
Department of Natural Resources
State of Alaska
Pouch "M"
Juneau, Alaska 99811

Dear Commissioner LeResche:

Following is a summary of information which has been prepared as required by Article 10.2(3)(h) of The Agreement for the Sale and Purchase of State Royalty Oil between Alaska Petrochemical Company and the State of Alaska dated February 22, 1978. A brief memorandum covering the work which has been done on plant design and process optimization is attached. More detailed information is available in each of these areas and can be made available for your review at your request. We are submitting to you today under separate cover copies of detailed engineering studies prepared for us by UOP Process Division, C-E Lummus Company, R. M. Parsons Company, Heat Research Corporation and Exxon Research and Engineering Company. An index of these materials is attached to this letter.

1. Plant Design

Preliminary studies of required facilities were prepared by Chem Systems, Inc. and Brown & Root. After approval of The Agreement on June 18, 1978, Chem Systems began more definitive studies with the assistance of Brown & Root personnel. Late in 1978, UOP Process Division was retained to carry out additional plant design studies based on their basic technology supplemented by special technology from Exxon Research and Engineering Co., R. M. Parsons Company, and Heat Research Corp. (a subsidiary of M. W. Kellogg, Inc.) These studies resulted in a processing plan to produce fuel products such as unleaded gasoline and jet fuel and chemical products such as benzene, toluene, and xylene. Using projected product demands and prices, the optimum plant design for the first phase of construction would produce fuel products, petrochemicals and petrochemical feedstocks that could be used in subsequent construction phases.

The products to be produced in the first phase are outlined in the report which has been submitted covering Article 10.2(3)(b) on product requirements, production ratios and quantities.

2. Optimization Studies

After completion of the preliminary plant design, studies were undertaken to further optimize the design. These studies were carried out by UOP and Alpetco personnel, using marketing data developed specifically for the West Coast and Pacific basin market area. Various computer studies were carried out to determine the economics of each unit which had been included in the plant design and the economics of various production levels of products. After extensive analysis, it was concluded that the original plant design should be retained with only minor revisions.

The optimized plant design includes four major units to produce such fuels as unleaded gasoline and jet fuel and petrochemicals such as benzene, toluene and xylene. In addition, olefins such as propylene and ethylene and such petrochemical feedstocks as paraffinic naphtha are available which could be converted into additional petrochemicals in subsequent phases of plant construction.

In addition to the plant design and optimization work which has been outlined above, additional process engineering has been carried forward. This work has covered the onsite and offsite facilities and has been done by the following organizations:

Exxon Research & Engineering Co.	-	Flexicoking
R. M. Parsons Company	-	Sulfur Recovery
Heat Research Corporation	-	Hydrogen Plant
UOP Process Division	-	All other plants including catalytic reforming, catalytic cracking and mild hydrocracking
C-E Lummus Company	-	All offsite facilities such as tankage, waste treatment, power plant, etc.
Santa Fe Engineering Co.	-	Product Dock

This engineering work has recently been completed and will serve as the basis for a project cost estimate.

We believe that the work which has been summarized above satisfies Article 10.2(3)(h) of The Agreement. We will be glad to discuss any aspect of this work if you so desire.

Very truly yours,

ALASKA PETROCHEMICAL COMPANY

Gordon A. Cain
President

GAC:br

w/attachment

Attachment

December 3, 1979

List of Detailed Engineering Studies

INDEX

1. Alaska Petrochemical Company, Valdez Refinery and Petrochemical Project, UOP Process Division

   Volume 1 - Process Selection
   Volume 2 - Process Optimization

2. Engineering for Cost Estimating, Alaska Petrochemical Refinery at Valdez, Alaska; UOP Process Division.

3. The Alpetco Company Oil Refining and Petrochemical Facility at Valdez, Alaska; Project Definition, C-E Lummus Company

   Section I
   Volumes 1 and 2 - Project Definition, General

   Section II
   Volume 1 - Project Definition, Onsite (ISBL) Facilities

   Section III
   Volumes 1 and 2 - Project Definition, Offsite (OSBL) Facilities

4. Sulfur Recovery Facilities, Proposal; The Ralph M. Parsons Company.

5. Process Specification - 40 MMSCF/D Hydrogen Plant; Heat Research Corporation.

6. Exxon Technology (Flexicoking Unit); Exxon Research and Engineering Company.

THE ALPETCO COMPANY

Refinery & Petrochemical Plant

Valdez, Alaska

PLANT DESIGN

Preliminary Studies:

Some of the preliminary studies for definition of the plant facilities for the project were carried out by Chem Systems, Inc. and Brown & Root. These studies visualized a major refining facility producing fuels with extensive petrochemical plants for processing available petrochemical raw materials into finished petrochemicals. These studies were developed to the point where a proposal could be prepared for submission to the State of Alaska. Preliminary cost estimates and preliminary economic analyses were made. These indicated that a very major facility would be required to provide refining capability and production facilities for large quantities of petrochemicals to be produced from the ethylene and benzene which were available raw materials.

More Definitive Planning Studies:

After the approval of the Royalty Oil Contract in June, 1978, additional studies were undertaken by Chem Systems and Brown & Root. For these studies the Chem Systems personnel carried out extensive computer simulations using data on individual process units which they obtained from process licensors. Brown & Root personnel developed cost estimates for each of these processing studies so that economic analyses

could be completed. Many of these studies were devoted to the definition of the optimum combination of refining capacity and petrochemical production capacity.

The general decline in the petrochemical market during 1978 and early 1979 and the significant upswing in the fuel products marketing picture prompted concentration on the facilities to produce fuel products and some petrochemicals with the production of additional petrochemicals deferred to a later phase. Because of their strong market position, primary petrochemical emphasis was placed on the production of benzene, toluene and xylene which are important building blocks for further petrochemical operations.

Late in 1978 the studies were carried into a second phase when the Process Division of UOP was retained to carry forward more extensive computer studies using their technology and technology which had been developed by other companies. Other technology selected for further study included the Flexicoking process by Exxon Research & Engineering for the conversion of the heavy fraction of the crude. The combination of this process technology with the capability to produce hydrogen and recover sulfur resulted in a complete plant which can produce a large quantity of high quality fuel products and substantial amounts of aromatic chemicals. Various alternative process combinations were studied, all directed toward the production of a product slate with the highest possible economic return which could be built in the severe Alaskan environment.

This processing scheme consisted of the basic refining processes provided by UOP including catalytic cracking, catalytic reforming and very mild hydrocracking. In addition, the Flexicoking technology from Exxon Research & Engineering was included in order to deal with the heavy fraction from crude. The combination of these produced an attractive return and was presented in the product slate and process flow plan descriptions which were prepared for presentation to possible participants in the project.

The process plan which was ultimately developed included the following key processing steps designed primarily to provide the most economical plant configuration.

Catalytic Reforming:

This process produces benzene, toluene and xylene, which can be extracted for sale as petrochemicals. It also produces high octane material for the production of gasoline. After the extraction of the aromatics, the remaining material is a very high quality paraffinic naphtha which can be used as a steam cracking feedstock to produce ethylene.

Mild Hydrocracking:

This process converts gas oil into high quality jet fuel. In the process, a large quantity of isobutane is produced which is required for olefin processing.

Catalytic Cracking:

This process converts gas oil into gasoline components with a large production of olefins. At the present time these olefins are to be converted into high octane blend stocks for gasoline, but could ultimately be recovered for the production of additional petrochemicals.

Flexicoking:

This process breaks up the heavy fraction of crude, normally sold as heavy fuel oil, and converts it into light products which can be fed to the other processing steps to produce additional fuel products and petrochemicals. By the use of this technology, a low BTU gas stream is produced which can be used to provide a substantial amount of the energy required for plant operation. The combination of this process

with the other conversion processes makes it possible to produce a large volume of high quality fuel products and petrochemicals from North Slope crude.

Offsite Design:

After the designs for the onsite part of the plant had been put together, the C-E Lummus Company prepared preliminary designs for the offsite facilities. These consist of tanks, docks, pipelines, blending facilities, power facilities, utility systems, and other support facilities required to provide an operable plant. During the design of these facilities, a plant layout was developed showing the location of each piece of equipment.

THE ALPETCO COMPANY

Refinery & Petrochemical Plant

Valdez, Alaska

OPTIMIZATION STUDIES

Upon completion of the work to preliminarily define the process plan, a major study was undertaken by the Process Division of UOP to optimize the design in preparation for more definitive process design. In order to carry out these studies the marketing situation was reassessed along with the pricing basis for products in 1984 and thereafter. In addition to this, the technology which had been considered for processing the heavy fraction of the crude was also reassessed. A detailed program was then developed for a series of computer runs to define the optimum process plan for the plant at Valdez.

The various computer runs, which have been summarized by UOP indicate that the original process configuration was very close to the optimum. Various size units have been considered in the main processing sequence in order to assure that the optimum design is carried forward into the next phase of the project. The specific areas which have been considered and the general conclusions which have been reached regarding them are as follows:

a. Mild Hydrocracking

The mild hydrocracking operation is a desirable process for upgrading light gas oil into jet fuel. Because of the large demands of the jet fuel market and the economic attractiveness of this fuel, a large hydrocracking unit is being included in the process

plan. The size of the unit has been determined by the volume of light gas oil which is available and the pressure level of the unit has been limited by the severity required to produce high quality jet fuel. Any further modifications to include heavier feed result in a larger unit, operating at a higher pressure level and requiring additional hydrogen production. After consideration of the various operating factors involved, it has been concluded that the low pressure unit feeding light gas oil should be included in the process design in the first phase of plant construction.

Additional aromatics production could be obtained by construction of a high pressure hydrocracking unit to produce naphtha from heavy gas oil as a second phase of plant construction.

b. Catalytic Cracking

The catalytic cracking unit has been revised to remove any recycle material from the feed. For satisfactory cracking of this recycle material, which is highly aromatic, a major investment would have to be made in hydrotreating and hydrogen production facilities to improve the quality of this stream. After a thorough economic evaluation it has been concluded that the catalytic cracking unit should be designed for once through conversion and that no treating of the cycle stock should be included in the design at this time. This is the only significant change from the original process plan.

c. Flexicoking

After a thorough evaluation of all bottoms processing schemes the Flexicoking technology provide the best combination of high liquid yields and minimum coke disposal. Other processing techniques make it necessary to produce a low value fuel oil. Further

steps have been taken to improve the design of the sulfur handling facilities for cleaning up the low BTU gas. It has been concluded that these facilities are sound and can be satisfactorily included in the design.

d. Catalytic Reforming

The catalytic reformer, which is a continuous reforming process of the latest design from UOP, will be increased in size so that in the event large quantities of virgin naphtha are available for production of gasoline, adequate reforming capacity will also be available. This naphtha can be produced by high severity hydrocracking of light gas oil.

Marginal Processing Steps:

In addition to an overall optimization of the plant, studies have been conducted on each of the peripheral processing plants in order to determine whether or not they should be included in the processing scheme. These peripheral plants are the Sulfolane extraction facilities for production of aromatics and the facilities for processing light olefins by polymerization or alkylation.

In the case of Sulfolane extraction of aromatics, it has been concluded that aromatics recovery is highly attractive provided that the raffinate can be disposed of at an attractive price based primarily on its value in gasoline. These facilities will produce a large quantity of aromatic petrochemicals which are very much in demand. The low octane byproduct raffinate is a very desirable steam cracking feedstock, or it can be used as a component for gasoline blending.

The alkylation facilities for handling mixed butylenes and propylenes to make alkylate for gasoline blending and the polymerization facilities for handling propylene will be sized

to optimize the processing of these olefins. These olefin streams could be used as petrochemical feedstocks for the next phase of plant construction. For the first phase these olefinic hydrocarbons will be converted to gasoline blending components.

We
think
we
ca—

PLEASE NOTE: THE PRECEDING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

THE ALPETCO COMPANY
3700 BUFFALO SPEEDWAY
HOUSTON, TEXAS 77098
TELEPHONE 713 840-1243 TELEX 791461

December 17, 1979

Dr. Robert E. LeResche
Commissioner
Department of Natural Resources
State of Alaska
Pouch "M"
Juneau, Alaska 99811

Re: Article 10.2(3) of the Agreement for the Sale and Purchase of State Royalty Oil between Alaska Petrochemical Company and the State of Alaska dated February 22, 1979 (the "Agreement")

Dear Commissioner LeResche:

During our meeting last Thursday, December 13, in Seattle, you and your associates raised certain questions concerning the material submitted to you at that meeting and we are herewith conveying material which we believe will clarify the points raised, all of which had to do with paragraph 10.2(3)(d) and (e) of the Royalty Oil Contract.

These points were as follows:

1. Two questions were raised regarding Thyssen's financing contract: one was the suggestion that the language of paragraph 3 of Thyssen's December 7, 1979 commitment letter be clarified [10.2(3)(d)]. The other question was whether or not Thyssen would agree to provide a commitment for interim financing for the construction of the Facility [10.2(3)(e)].

   Included herewith is Thyssen's telex which clarifies the language in question and which commits to provide interim construction financing, if and when needed.

2. A question was raised by Don Holman, Esq. of Preston, Thorgrimson, Ellis and Holman as to whether or not the City of Valdez could issue industrial revenue bonds in connection with Alpetco's financing without violating AS 37.10.085.

   Enclosed herewith are two legal opinions, one dated December 13, 1979 from Wohlfarth and Flint (with enclosures), bond counsel for the City of Valdez, and an opinion dated December 14, 1979 from Kutak, Rock & Huie, bond counsel for EF Hutton & Company Inc.

3. A question was raised under paragraph 3 of the May 17, 1978 amendment to the Royalty Oil Agreement as to whether or not Alaska Interstate would be willing to commit for all of Alaska Petrochemical's share of the $100 million commitment required under the amendment.

601 WEST 5TH AVENUE, ANCHORAGE, ALASKA, 99501, TELEPHONE 907 272-1517, TELEX 090-251157

Alaska Interstate Company's answer was affirmative and transmitted herewith is a letter dated December 14, 1979 whereby Alaska Interstate Company commits to fulfill all of Alaska Petrochemical Company's portion of the $100 million commitment, if necessary.

4. Also transmitted herewith is Alaska Petrochemical Company's Progress Report No. 18 dated December 18, 1979.

The above material along with that transmitted to you at our December 5, 1979 meeting in Juneau and our December 13, 1979 meeting in Seattle, together with the testimony given at those meetings, in our opinion successfully complies with all of the December 18, 1979 "Benchmarks" on the Royalty Oil Agreement.

Sincerely,

Gordon A Cain

Gordon A. Cain
President

GAC:t
Enclosures.

Rec'd 12-17-7
10 25 am

RCA DEC 17 1106+
ALPETCO HOU

8588561Z TRT D 17.12.79 FS NR. 45276 SCHWARZE/WK 17.10

ATTENTION: MR. CHARLES HONIG OR MR. GORDON CAIN

PLEASE FIND HEREIN BELOW OUR REVISED WORDING FOR COMMITMENT LETTER:

GENTLEMEN:

IN CONSIDERATION OF ALPETCO ENTERING INTO THE ATTACHED ENGINEERING- AND CONSTRUCTION-CONTRACT WITH THYSSEN RHEINSTAHL TECHNIK GMBH (THYSSEN) AND FOSTER WHEELER ENERGY CORPORATION FOR THE ENGINEERING, SUPPLIES, AND CONSTRUCTION OF THE FACILITIES OF ALPETCO'S VALDEZ, ALASKA REFINERY AND PETROCHEMICAL FACILITY (PROJECT), SUCH PROJECT HEADED BY THE ALPETCO COMPANY (ALPETCO) - A JOINT VENTURE PARTNERSHIP OWNED BY CHARTER OIL (ALASKA), INC., A SUBSIDIARY OF THE CHARTER COMPANY, ALASKA PETROCHEMICAL COMPANY AND E.F. HUTTON (ALASKA) INC. - WE HEREBY COMMIT TO ARRANGE FINANCING OF UP TO US-DOLLAR 750,000 000,-- (SEVENHUNDREDANDFIFTY MILLION US-DOLLARS) TO COVER COSTS FOR THE ENGINEERING, EQUIPMENT, MATERIALS, CONSTRUCTION AND OTHER SERVICES REQUIRED FOR THE PROJECT.

IN ADDITION TO ARRANGING THE ABOVE FINANCING, WE HEREBY ALSO COMMIT TO ARRANGE INTERIM FINANCING FOR THE CONSTRUCTION OF THE PROJECT OF UP TO US DOLLAR 150,000,000 (ONEHUNDREDANDFIFTY MILLION US-DOLLARS) IF AND AS NEEDED, PROVIDED THE EXISTING BANK COMMITMENTS DO NOT MATERIALIZE.

OUR COMMITMENTS HEREUNDER ARE SJUBJECT TO THE FOLLOWING:

western union

1. ALPETCO'S ACQUIRING AND CONTRIBUTING TO THE PROJECT FINANCING OF AT LEAST US DOLLAR 750,000,000,-- (SEVENHUNDREDANDFIFTY MILLION US-DOLLARS) BY A COMBINATION OF THE ISSUANCE OF INDUSTRIAL REVENUE BONDS, EQUITY INVESTMENT AND/OR SATISFACTORY FORMS OF FINANCING BY ALPETCO'S PARTNERS AS ARE REQUIRED FOR THE PROJECT IMPLEMENTATION,
AND

2. ALPETCO'S OBTAINING ALL NECESSARY APPROVALS AND PERMITS REQUIRED BY THE RESPONSIBLE AUTHORITIES FOR THE CONSTRUCTION AND OPERATION OF THE PROJECT, THE ROYALTY CRUDE OIL CONTRACT BEING IN EFFECT AND ALPETCO HAVING THE RIGHT TO TAKE CRUDE OIL NOT LATER THAN JULY 18, 1980,
AND

3. EXECUTION OF DEFINITIVE DOCUMENTS RELATING TO THE LONG-TERM FINANCING FOR THE PROJECT ON OR BEFORE DECEMBER 18, 1980.

IF THE ABOVE DEFINITIVE AGREEMENTS ARE NOT ENTERED INTO BY SUCH DATE, WE RESERVE THE RIGHT TO TERMINATE OUR COMMITMENT HEREUNDER WITHOUT ANY LIABILITY ON OUR PART.

THIS LETTER REPLACES OUR DECEMBER 7, 1979 LETTER TO YOU ON THE SAME SUBJECT, A COPY OF WHICH IS ATTACHED HERETO.

YOURS FAITHFULLY,
W. SCHWARZE / THYSSEN RHEINSTAHL TECHNIK GMBH

ALPETCO HOU

85685612 TRT D

western union

AGO 560056

Thyssen Rheinstahl Technik GmbH · Postfach 80 23 · 4000 Düsseldorf 1

THYSSEN RHEINSTAHL TECHNIK GMBH

The Alpetco Company
3700 Buffalo Speedway
Houston, Texas 77098
U. S. A.

Thyssen Technik-Haus
Königsallee 106
Düsseldorf

Ihre Zeichen	Ihre Nachricht vom	Unsere Zeichen	Unser Hausruf (Direktwahl) (02 11) 3803-	Düsseldorf
		Recht/Dr.W./ho		December 7, 1979

Betreff

Gentlemen:

In consideration of Alpetco entering into the attached Engineering- and Construction-Contract with Thyssen Rheinstahl Technik GmbH (Thyssen), or a Joint Venture consisting of Thyssen and another party nominated by Thyssen, for the engineering, supplies and construction of the facilities of Alpetco's Valdez, Alaska Refinery and Petrochemical Facility (Project), such Project headed by The Alpetco Company (Alpetco) - a Joint Venture partnership owned by Charter Oil (Alaska), Inc., a subsidiary of The Charter Company, Alaska Petrochemical Company and E.F. Hutton (Alaska), Inc. - we hereby commit to arrange financing of up to US$ 750,000,000.-- (sevenhundredandfifty million US-Dollars) to cover cost for the engineering, equipment, materials, construction and other services required for the Project.

Our commitment hereunder is subject to Alpetco's acquiring and contributing to the Project financing of at least US$ 750,000,000.- (sevenhundredandfifty million US-Dollars) by the issuance of industrial revenue bonds, equity investment and other satisfactory forms of financing by Alpetco's partners as are required for the Project implementation.

AGO 560057

Geschäftsführung: Dr. Helmut Gschwend (Vorsitzender)

Handelsregister-Nr. HR B 3311

Definitive agreements for all the financing required shall be entered into by December 18, 1980, on such terms and conditions as are customarily required for similar financings by lenders at such time. If such definitive agreements are not entered into by such date, we reserve the right to terminate our commitment hereunder without any liability on our part.

The financing shall be subject to Alpetco obtaining all necessary approvals and permits required by the responsible authorities for the construction and operation of the Project, the Royalty Crude Oil Contract being in effect and Alpetco having the right to take crude oil not later than July 18, 1980.

Yours faithfully,

THYSSEN RHEINSTAHL TECHNIK
G.m.b.H.

PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

December 13, 1979

Mr. Mark Lewis, Manager
City of Valdez
P. O. Box 307
Valdez, Alaska 99686

Dear Mr. Lewis:

A question has apparently been raised as to whether the proposed industrial revenue bond financing by the City of Valdez for Alpetco violates AS 37.10.085 which prohibits either the state or political subdivision to lend its credit for the use of a private corporation or to borrow money for the use of a private corporation.

In our opinion, the answer to the above question is clearly no. We point out to you at the outset that the entire City of Valdez Marine Terminal Revenue Bond program was effectuated under the same provisions of the City Charter and in light of AS 37.10 .085. This financing was accomplished after extensive legal research. The principal case cited in the legal research was Wright v. City of Palmer, 468 P.2d 326 (Alaska, 1970) where the court deals with the precise issue on page 328 and 329. The court there held that a general obligation bond issue of the City of Palmer to purchase an industrial plant site for a specific private corporation did not violate AS 37.10.085 and was consistent with specific provisions of the Alaska Constitution.

For the benefit of Don Holman, Esq. of Preston, Thorgrimson, Ellis & Holman who has apparently raised the question, we are enclosing a copy of our memorandum of law on this subject matter and a copy of the case of Wright v. City of Palmer.

If you have any other questions with respect to this matter, please do not hesitate to call on us. Because the matter is urgent, we are telecopying this opinion directly to you and will mail to Mr. Holman a copy with a copy of the above-referenced enclosures.

Very truly yours,

WOHLFORTH & FLINT

By
Eric E. Wohlforth

EEW/lw

cc: Don Holman, Esq.

AGO 560059

April 4, 1977

[illegible] Company, U.S.A.
[illegible]
[illegible] Texas 77001

Attention: [illegible], Esq.

Sirs:

You have asked our opinion as to the authority of the City of Valdez, Alaska, to issue Marine Terminal Revenue Bonds without specific state statutory authorization. It is our opinion that the City has this power as a home rule city of the State of Alaska. Further, in our view, this power was validly exercised consistent with the Alaska State Constitution by the City in the proceedings pursuant to which $265,000,000 City of Valdez, Alaska, Marine Terminal Revenue Bonds (ARCO Pipe Line Company Project) Series 1977 were issued on February 15, 1977. We set forth our reasoning and legal analysis below.

Home Rule Question

Sections 1 through 8 of Article X of the Alaska Constitution establish the structure of local government in the State of Alaska. Sections 9, 10 and 11 of Article X of the Constitution provide the basis for home rule municipalities in the State of Alaska. Section 9 of Article X states:

> "The qualified voters of any borough of the first class or city of the first class may adopt, amend, or repeal a home rule charter in a manner provided by law. In the absence of such legislation, the governing body of a borough or city of the first class shall provide the procedure for the preparation and adoption or rejection of the charter. All charters, or parts or amendments of charters, shall be submitted to the qualified voters of the borough or city, and shall become effective if approved by a majority of those who vote on the specific question.

Section 10 of Article X states:

> "The legislature may extend home rule to other boroughs and cities."

And Section 11 of Article X states:

> "A home rule borough or city may exercise all legislative powers not prohibited by law or by charter."

These constitutional provisions are further expanded by statute. Section 29.08.010 of the Alaska Statutes Annotated provides that:

> "A home rule municipality is a municipal corporation and political subdivision and is a borough of the first class or city of the first class which has adopted a home rule charter. It has all legislative powers not prohibited by law or by charter."

Article 1 of Chapter 13 of Title 29 provides for the adoption and amendment of charters for home rule municipalities. Article 2 of Chapter 13 of Title 29 places certain limitations on home rule municipalities.

We have, of course, concluded that the City of Valdez Charter was validly adopted and that its amendments have been validly adopted. We refer you specifically to the Charter Amendment adopted in connection with the issuance of Industrial Development Bonds attached hereto as Appendix A.

The Supreme Court of Alaska in Jefferson v. State, 527 P.2d 37 (Alaska 1974) set down the limits of home rule power of Alaska charter cities. In Jefferson v. State the court reviewed the earlier four cases analyzing the home rule provision of the State Constitution (Article X, §11) as well as the two Law Review articles which had analyzed and critized the court's earlier opinions. In Jefferson v. State, the court held that Article X, §11, which states that:

> "A home rule borough or city may exercise all legislative powers not prohibited by law or charter."

meant what it says, namely that there must be a prohibition on the exercise of municipal power arising from the law or charter for a power to be denied to home rule municipalities.

At 527 P.2d, page 43, the court stated that:

> "The test we derived from Alaska's Constitutional provisions is one of prohibition, rather than traditional tests such as statewide versus local concern. A municipal ordinance is not necessarily invalid in Alaska because it is inconsistent or in conflict with the State statute. The question rests on whether the exercise of authority has been prohibited to municipalities. The prohibition must be either by express terms or by implication such as where the statute and ordinance are so substantially irreconcilable that one cannot be given its substantive effect if the other is to be accorded the weight of law."

The case is important because the court in earlier opinions, principally Chugach Electric Association v. City of Anchorage, 476 P.2d 115 (Alaska 1970) and Macauley v. Hildebrand, 491 P.2d 120 (Alaska 1971), had indicated its preference for the test of the so-called "local activities rule". As stated in the concurring opinion in Jefferson v. State, which advocated the adoption of the "local activities rule", this rule requires the court to focus upon whether the particular subject under consideration is of such statewide concern that the exercise of municipal power is inconsistent with the effectuation of statewide policy, as expressed by statute. The court's adherence to this test in the two other recent cases prior to Jefferson v. State had been extensively critized in Sharp, Home Rule in Alaska: A Clash Between the Constitution and the Court, 3 UCLA-Alaska L.R. 1 (1973). The author of the Law Review article stated at page 53

> "In the ten years that followed statehood the court refrained from seeking guidance from other states in that interpretation of its home rule grant, and in the Lien, Maier and Rubey decisions displayed an understanding of the intent of the constitutional provision. These three decisions set a pattern of broad, constitutionally based home rule powers and of a liberal judicial construction of home rule powers. However, in Chugach, a case which followed a substantial change in court personnel, the court reversed both patterns. It adopted the state-local test, which it denominated the 'local activities rule', with the result that where any statewide interest is at stake a state statute which is inconsistent with an ordinance of a home rule municipality will constitute a prohibition."

In Jefferson v. State, however, the court stated that the framers of the Constitution

> " . . . were aware of the difficulties encountered in other jurisdictions where delegations of power to local units were conferred in terms, such as 'matters of local concern' or of local affairs which were intended to create an exclusive sphere of municipal action free from any intrusion by the state legislature." (527 P.2d 37, 43)

The court stated that attempts by the courts of those jurisdictions to resolve conflicts had led to confusion and inconsistencies and, in view of this, that the constitutional delegates undertook to give Alaska home rule municipalities a wide range of powers to meet the differing needs of the widely scattered communities within the state. They hoped that the Article X, §11 grant of home rule authority would lead the courts to take a new approach to the subject of conflicts between municipalities and the state.

The court in Jefferson v. State returned to the legal rationale adopted in Rubey v. City of Fairbanks, 456 P.2d 470, 475 (Alaska 1969) stating it declined to follow California's pre-emption-by-state-occupation-of-the-field-doctrine because of the difference between California's and Alaska's home rule provisions. The court stated that the foundation for the "new approach" resolving conflicts between municipalities and the state had been laid in past decisions of the Alaska Supreme Court which favored the exercise of legislative powers by local government units. For the last statement, the court cited Lien v. City of Ketchikan, 383 P.2d 721-723 (Alaska 1963); City of Juneau v. Hixson, 373 P.2d 743 (Alaska 1962); Rubey v. City of Fairbanks, 456 P.2d 470-475 (Alaska 1969).

In Jefferson v. State the court clearly reverted to the rationale of the Rubey case citing it three times in rejecting the test of the "local activities rule". In stating that the "prohibition test" is the one upon the Alaska Supreme Court will decide cases it stated at footnote 33 as follows:

> "We affirm our rejection of the doctrine of state pre-emption by 'occupying the field'. We will not read into a scheme of statutory provisions any intention to prohibit the exercise of home rule authority in the area of the law. If the legislature wishes to 'pre-empt' an entire field, they must so state. See Rubey v. City of Fairbanks, 456 P.2d 470 (Alaska 1969).
>
> We note that the legislature has done this in its new Title 29, Municipal Code. AS 29.13.100 provides in part:
>
> 'Only the following provisions of this title apply to home rule municipalities as prohibited on acting otherwise than as provided.'"

The significance of Jefferson v. State becomes clear when the UCLA-Alaska Law Review article is read. The author of the article stated that the Chugach case was a

radical deviation and a reversal from the line of home rule decisions that preceded it. Jefferson v. State on the other hand shows that the Supreme Court was aware of its error in adopting the local activities rule. The opinion stands as a guide to home rule cities that they may legislate in all areas not prohibited by law or charter.

It may be argued that in some cases application of the "prohibition" instead of the "local activities" test is not of major importance since the results tend to be the same. Certainly in Jefferson v. State the court held that the Anchorage Charter provision against sale of public utilities except by three-fifths vote fell in light of the general law provision that the area wide sewer power could no longer be exercised in the City once it had been properly assumed by the Borough. In the next case of conflict between state law and municipal home rule ordinance, Adkins v. Lester, 530 P.2d 11 (Alaska 1974), the court held that a Fairbanks city ordinance to the extent that it was in conflict with state traffic regulations constituted an exercise of home rule power expressly prohibited by the legislature. The court cited with approval on its previous statement in Jefferson v. State, at 527 P.2d 43 namely that the question of validity of municipal ordinances rests whether the exercise of the authority has been prohibited to municipalities.

The significance, however, of the adoption of the "prohibition" test in the instant situation, as opposed to the "local activities" test, lies in the fact that the provisions of the home rule charter of the City of Valdez and state law need alone be addressed in determining whether or not the City can issue bonds for marine terminal purposes. The court in deciding whether or not this power may be exercised need not consider whether the borrowing by the City for this purpose is a matter of statewide concern. Such an examination would be required under the local activities test.

The court was assisted in Jefferson v. State by the legislative expression in AS 29.13.100 which provides in part:

> "Only the following provisions of this title apply to home rule municipalities as prohibitions on acting otherwise than as provided."

At footnote 33, at 527 P.2d page 43 the court stated that: "If the legislature wishes to pre-empt the entire field, they must so state."

In Kodersick v. Sullivan, 526 P.2d 450 (Alaska 1974) at page 455, the court noted that AS 29.13.100 constituted a specific provision that state law on reapportionment (AS 29.23.020) prohibited future home rule enactments which provide otherwise, quoting with approval Jefferson v. State. The court again quoted Jefferson v. State in Adkins v. Lester, 530 P.2d 11 at page 15 in determining that the legislature had expressly prohibited a home rule city from enacting an ordinance in conflict with state regulations in regard to the use and operation of motor vehicles.

The holding of the Jefferson v. State affirms the uniqueness of the Alaska Constitutional home rule provision and makes inapplicable most of the law review articles and cases in other states dealing with the scope of home rule.

As noted in the footnote 26 at Jefferson v. State, 527 P.2d 42, Alaska's home rule provision is a "sword" not a "shield". It does not carve out any area where the state may not act by requiring a court determination of whether the exercise of a municipal power is statewide or local in nature. The court does not have to make such a determination because it must only determine whether the exercise of power is prohibited to municipalities. In discussing the Alaska home rule constitutional provision at 48 Minnesota Law Review 643, 686 The Limits of Municipal Power Under Home Rule; A Role for the Courts, Terrance Sandalow, it is stated that it grants broader power than is granted in any other state constitution.

The court's interpretation of the home rule provision in Article X, §11 of the State Constitution is consistent with §1 of Article X, the introductory section to the Article on Local Government in the Alaska Constitution, which reads:

> "The purpose of this article is to provide for a maximum local self government with a minimum of local government units, and prevent duplication of tax-levying jurisdiction. A liberal construction shall be given to the powers of local government units."

The most recent dealing with Article X, §11 of the Alaska Constitution is Area Dispatch, Inc. v. City of Anchorage, 544 P.2d 1024 (Alaska 1976). The court found no prohibition in State law on the City establishing a lessor percentage of signatures necessary for referendum vote than fixed in State law. It instead found that the Charter itself fixed the limitation by reference to State law. Before holding on the point the court stated:

> "Article X, §11, of the Alaska Constitution provides that home rule cities 'may exercise all legislative power not prohibited by law or charter'. Numerous court opinions and commentators have explained that a municipal ordinance of a home rule municipality is not invalid because it is inconsistent or in conflict with a state statute. The question of validity of the conflicting ordinance rests on whether the exercise of the authority has been prohibited to home rule municipalities. 'The prohibition must be either by express terms or by implication such as where the statute and ordinance are so substantially irreconcilable that one cannot be given its substantive effect if the other is to be accorded the weight of law.'"

It cannot be said, in our view, that the State legislation permitting industrial development bond financing through the Alaska Industrial Development Authority (AS 44.61) constitutes an implied prohibition on the City of Valdez undertaking such a financing. This statute and Ordinance No. 7525 of the City are in no degree "irreconcilable". Further, port financings have as a factual matter been undertaken by Alaska cities such as Anchorage for many years even though the freight activity is by no means limited to that city.

Public Purpose Question

Article IX, Section 6 of the Alaska Constitution provides that

> "No tax shall be levied, or appropriation of public money made, or public property transferred, nor shall the public credit be used, except for a public purpose."

The leading and original case on revenue bond financing in Alaska is DeArmond v. Alaska State Development Corporation, 376 P.2d 717 (Alaska 1962). The Corporation's function was to provide mortgage money for development loans within the State. The court held that the issuance of revenue bonds or debentures secured only by revenues of the Corporation to raise money for this purpose did not violate Article IX, Section 6 for two reasons. First, it found that the Corporation did serve a public purpose and in so finding it held that a State loan of $150,000 to the Corporation was valid. Secondly, it found that since the Corporation's bonds are payable only from revenues of the Corporation, and that the State was not indebted or obligated meant that the transaction did not violate Article IX, Section 6. The court stated at page 722 as follows:

> "No public funds are being transferred to the corporation other than the loans just mentioned. Funds realized from the sale of certificates will come from private sources. The credit of the State is not being pledged. Even though we have found that the corporation's activities will serve a public purpose, it is clear enough that its objectives must be accomplished without the use of public funds and State credit. No violation of the Constitution has been shown."

In Walker v. Alaska State Mortgage Association, 416 P.2d 245 (Alaska 1966), the court followed its holding in the DeArmond case in finding that activities of the Association in the selling of bonds to provide funds to make mortgage loans constituted a public purpose. The court held that the authority to issue bonds did not violate Article IX, Section 8 of the Constitution which requires that State debts be authorized for capital improvements and ratified by the voters. The court stated that

> "In DeArmond, we concluded that the funds realized through the sale of bonds backed only by the resources and credit of the corporation and which did not constitute debts of the State were not public funds. We are of the opinion that our holding in DeArmond is controlling here and conclude that bonds, notes and debentures of the association are not debts of the State of Alaska within the scope of Article IX, Section 8 of our Constitution."

Two things should be noted about these above two cited cases. First, the court found that the funds derived from the sale of revenue bonds are not public funds and in two cases holds that this is an independent ground for the transaction not to be prohibited by Article IX, Section 6. Secondly, in the Walker case the court has direct occasion to consider whether or not the restriction that State debt must be issued for capital improvements applies to revenue bonds issued by a corporation of the State and never even considers the point but holds nevertheless that the revenue bonds should not be characterized as State debt under Article IX, Section 8.

The other major Alaska case considering the above question is Wright v. City of Palmer, 468 P.2d 326 (Alaska 1970). The court there considered whether or not the authorization by the City of Palmer of general obligation bonds to provide funds to construct a manufacturing plant for lease to private enterprise violated the lending of credit provision of AS 37.10.085 which prohibits either the State or a political subdivision from lending its credit for the use of a private corporation, or borrowing money for the use of a private corporation. The court also considered whether the transaction violated Article IX, Section 6 of the Alaska Constitution. The court concluded that the question of whether the public credit is being pledged for private purposes was also comprehended under the broader question of whether a public purpose was served by the bond issue and plans for its expenditure. In holding that the plan did constitute a public purpose it cited DeArmond and Walker. The second ground of Walker and DeArmond, namely, that since the bonds were revenue bonds, payable only from project

revenues, there was no violation of Article IX, Section 6, was obviously not available to the court. The court stated however, in footnote four on page 329 that

> "The courts which have upheld bonding projects as a legitimate exercise of power by the political subdivisions have held that a statute which pledges only project revenues does not pledge the public credit, and, therefore does not lend the public credit in aid of anyone." (citing cases)

There are several additional features of Wright v. City of Palmer, which are relevant to the instant situation. In the first place it should be noted that unlike the situation in DeArmond and Walker there was no specific authority in State statutes for the transaction. That is to say the Legislature had not directly spoken on the subject matter nor had it made legislative findings that a public purpose would be served by authorizing the issuance of local government bonds for manufacturing or industrial plants. The fact that the Legislature had spoken in other contexts on the desirability of public assistance to induce new industries was briefed and noted by the court in its reference to the power of the City Council to lease property to industries. In any event, the important fact is that the court considered the action of the City Council of Palmer to have equal dignity with State legislative action on the subject matter. It stated that

> "The role of the courts in matters of this kind is relatively limited. Our function is not to determine whether, as prudent burghers, we might think this plan wise . . ."
>
> "If the city fathers and the voters of the community feel that this plan of action is necessary, it is not for us to retard them. It is within their legislative province to determine whether the advantages outweigh the risks."

The limits which Justice Connor set on the scope of the court's function in deciding these matters is of importance in determining the rationale of the decision. The court states at page 331

> "If the plan of action were plainly foolhardy, or if amounted to the pledging of credit or giving away of assets without any corresponding discernible benefit, we might be persuaded to strike down the plan."

There is nothing in this judicial expression of the court's role in determining cases of this nature which indicates that a plan of action would be found unconstitutional if indeed it could be proven that a particular industry would have located within municipal boundaries regardless of the availability of public financing. Although the case seems to assume that the availability of public financing was an inducement to location there is nothing in the record that the fact of location without the public financing would cause the court to strike the plan down. The court did state the perameters of judicial scrutiny, namely, that the plan must be plainly foolhardy or amount to the pledging of credit or the giving away of assets without any corresponding discernible benefit in order for it to be striken. There is nothing in our view, in the instant situation which can be characterized under this terminology and indeed, assisting in the financing of the pipeline has obvious direct and ancillary public purpose benefits both to the State of Alaska and to the City.

If you require further analysis of the above points, please call on us.

Very truly yours,

WOHLFORTH & FLINT

By_____
Eric E. Wohlforth

EEW:jr

Neal WRIGHT, Appellant,

v.

CITY OF PALMER, Municipal Corporation, State of Alaska, Theodore Schmidtke, Mayor, Emilie St. Pierre, City Clerk, and Members of the City Council of the City of Palmer, Appellees.

No. 1192.

Supreme Court of Alaska.
April 27, 1970.

Declaratory judgment action to invalidate city's issuance of general obligation bonds. The Superior Court, Third Judicial District, C. J. Occhipinti, J., granted judgment, and appeal was taken. The Supreme Court, Connor, J., held that issuance of general obligation bonds to finance a 20-year improvement program providing for purchase of a site and construction of a manufacturing and processing facility which would be leased to a private corporation did not, under circumstances presented constitute an unlawful lending of credit to a private corporation and did not constitute a violation of "capital improvement" and "public purpose" requirements of Constitution.

Affirmed.

1. Municipal Corporations ⇐722

It is within statutory power of a city to make available industrial sites which may be of benefit to municipality and to lease them on terms which are advantageous to public welfare of city. AS 29.10.132(c).

2. Municipal Corporations ⇐869, 873

Issuance of general obligation bonds to finance a 20-year improvement program providing for purchase of a site and construction of a manufacturing and processing facility to be leased to a private corporation, where significant restrictions and controls were retained by city over corporation's operations, did not constitute a violation of statute prohibiting the state or a political subdivision from lending its credit or borrowing money for use of a private corporation. AS 37.10.085.

3. Municipal Corporations ⇐911

Land and building to be obtained by municipality through issuance of general obligation bonds under a 20-year improvement program providing for purchase of a site and construction of a manufacturing and processing facility, where city's real ownership of structure would increase as years of rental payment went by, constituted "capital improvements" within Constitution providing that no debt shall be contracted by a political subdivision unless for capital improvements. Const. art. 9, § 9.

See publication Words and Phrases for other judicial constructions and definitions.

4. Municipal Corporations ⇐911

In determining whether a community development plan financed through issuance of general obligation bonds fulfills "public purpose" requirement of Constitution, test is whether plan is so unreasonable as to transgress limitations of Constitution. Const. art. 9, § 6.

5. Municipal Corporations ⇐910

Although development of industry within a community through issuance of general obligation bonds is not always an unmixed blessing, as it may impose burdens on other public facilities, it is hard to see how municipality, contrary to "public purpose" provision of Constitution would be hurt by location of an industry within its boundaries, where its plight is that of an eroding economic community and where city fathers and voters of community feel that a plan of action is necessary. Const. art. 9, § 6.

Eric E. Wohlforth, of McGrath & Wohlforth, Anchorage, for appellant.

Burton C. Biss, Anchorage, for appellees.

OPINION

Before DIMOND, Acting Chief Justice, and RABINOWITZ, BONEY, and CONNOR, Justices.

AGO 560072

CONNOR, Justice.

This case questions the validity of a general obligation bond issue for the purpose of encouraging industrial development within a municipality. This is a declaratory judgment action in which appellant, in his capacity as a resident of and owner of real and personal property in the City of Palmer, seeks to have declared invalid the issuance of bonds by the city. These bonds were authorized at a special election at which the proposition carried by a vote of 248 in the affirmative and 7 in the negative. The proposition submitted to the voters was as follows:

PROPOSITION NO. 1

Shall the City of Palmer, Alaska, issue general obligation bonds in an amount not to exceed Four Hundred Fifty Thousand Dollars ($450,000.00) for the following purpose: Under a 20-year improvement program providing for the purchase of a site and the construction of a manufacturing and processing facility within the City of Palmer. All said general obligation bonds shall mature within twenty years from the date of issue and bear interest at a legal rate.

After the proposition was approved by the voters, the city entered into an agreement with Huskey Manufacturing Corporation, a manufacturer or assembler of industrial housing, low-cost residential housing and mobile homes, by which the corporation agreed that it would in the future enter into a lease and occupy the building to be constructed, for a period of not less than 20 years, to keep its raw materials within the city limits in order to render it subject to personal property taxation, to employ not less than 80% of its personnel from the Palmer area, to maintain training facilities for its employees, and to maintain on-the-job training programs under federal and state auspices. It also agreed, as a condition to entering into a lease, that it would use the public utilities owned by the city, as far as they are available. The company agreed that the paved parking lot adjacent to the building should be available at all reasonable times for public recreational uses. The agreement also provides that the rental shall be fixed in such an amount that the total cost of the project, including the sums necessary to amortize the bonds sold to finance the project, shall be payable over a 20-year period under a reasonably uniform schedule through the term of the lease. In short, the city would procure or make available land and a structure for the use of the lessee, using the bond proceeds to accomplish this end.

This case obviously has been brought for the purpose of testing the validity of the bond issue and to determine whether the bonds are marketable. The record is somewhat one-sided in that all of the evidence was presented by the city, although the witnesses for the city were cross-examined by counsel for appellant. On the other hand, the legal questions have been thoroughly argued and briefed. Unlike the situation in Ault v. Alaska State Mortgage Association, 387 P.2d 698 (Alaska 1963), we do find the record sufficient for determining the legal issues presented in this case.[1] Unlike *Ault*, where a summary judgment was entered, this case went to a trial on

1. In Jefferson v. Asplund, 458 P.2d 995, 998 (Alaska 1969), this court held that an actual controversy is a prerequisite to the granting of declaratory relief under the Alaska statute permitting declaratory judgment actions. We further cited with approval the definition of "controversy" found in the opinion by Chief Justice Hughes in Aetna Life Insurance Company of Hartford, Conn. v. Haworth, 300 U.S. 227, 57 S.Ct. 461, 81 L.Ed. 617 (1937):

> "A 'controversy' in this sense must be one that is appropriate for judicial determination. * * * A justiciable controversy is thus distinguished from a difference or dispute of a hypothetical or abstract character; from one that is academic or moot. * * * The controversy must be definite and concrete, touching the legal relations of parties having adverse legal interests." (Citations omitted.)

the merits under the provisions of Rule 57(a), Rules of Civil Procedure.[2]

The testimony and evidence presented show a pattern of serious economic problems which the City of Palmer is seeking to overcome. The City Council in the agreement to lease makes a recital of its findings about the economic plight of the City of Palmer and its environs. The pattern which emerges from the evidence is that over the course of the last several years the economic growth of Palmer has been nil. The Palmer Comprehensive Development Plan of 1967, prepared by the city, discloses a high year-round rate of unemployment. Virtually no manufacturing exists in the City of Palmer. At one time coal mines were operated in the Palmer area, but these have been shut down because Elmendorf Air Force Base and Fort Richardson, the prime consumers of coal, now utilize natural gas for heating and the generation of electricity. The closure of the mines has resulted in a loss of payroll for the Palmer area estimated at something over one million dollars per annum. Lumber processing has ceased in the Palmer area, with a loss of about 20 jobs. Various other business activities have moved out of the Palmer area recently, including the Matanuska Valley Cooperative Association, the Sears & Roebuck store, and other businesses. Palmer has recently been declared a depressed area by the federal government. It is in an effort to combat this declining economy that the city has proposed the issuance of bonds, the erection of a manufacturing building, and its lease to a private corporation. It is estimated that the proposed project, when fully operational, would employ approximately 65 to 110 persons on a full-time basis.

IS THERE AN UNLAWFUL LENDING OF CREDIT?

[1, 2] It is asserted that the bond issue and plan of action violates AS 37.10.085,[3] which prohibits either the state or a political subdivision to lend its credit for the use of a private corporation, or to borrow money for the use of a private corporation. We note at the outset that the city is not handing money directly to a private

2. "Rule 57. Declaratory Judgments - Judgments by Confession. (a) Declaratory Judgments. The procedure for obtaining a declaratory judgment pursuant to statute shall be in accordance with these rules, and the right to trial by jury may be demanded under the circumstances and in the manner provided in Rules 38 and 39. The existence of another adequate remedy does not preclude a judgment for declaratory relief in cases where it is appropriate. The court may order a speedy hearing of an action for a declaratory judgment and may advance it on the calendar."

Many actions such as the one in the instant case have been entertained by other state courts.

"Municipal financing legislation and projects have frequently been questioned in taxpayer suits, on the ground that they violate state constitutional provisions prohibiting the use of public funds or credit for purposes which are not 'public.' Often such suits are brought by industrialists and others who seek prior judicial approval of a project. [Footnotes omitted.] In most cases, the projects and legislation have been upheld. [Newberry v. City of Andalusia, 257 Ala. 49, 57 So.2d 629 (1952); Wayland v. Snapp, [232 Ark. 57], 334 S.W.2d 623 (Ark.1960); Dycke [sic] v. City of London, 288 S.W.2d 648 (1956); Miller v. Police Jury, 226 La. 8, 74 So.2d 391 (1954); City of Frostberg [Frostburg] v. Jenkins, 215 Md. 9, 136 A.2d 872 (1957); Village of Deming v. Hosdreg Co., 62 N.M. 18, 303 P.2d 920 (1956); Holly v. City of Elizabethton, 193 Tenn. 40, 241 S.W. 2d 1001 (1951); McConnell v. City of Lebanon, 203 Tenn. 498, 314 S.W. 2d 12 (1958). *Contra*, State v. Town of No. Miami, 50 So.2d 779 (Fla.1952); State ex rel. Beck v. City of New York, 161 Neb. 223, 82 N.W.2d 239 (1957).]" 70 Yale Law J. 789, at 791 and n. 15, "The 'Public Purpose' of Municipal Financing for Industrial Development."

3. "Financial aid to corporations by state or political subdivision. Neither the state nor a political subdivision of the state may (1) make a subscription to the capital stock of a corporation; (2) lend its credit for the use of a corporation; or (3) borrow money for the use of a corporation."

corporation. Nor is it pledging that its credit or taxing powers may be used to make good the indebtedness of a private person in contravention of the Alaska Constitution.[4] It is within the statutory power of a city to make available industrial sites which may be of benefit to the municipality and to lease them on terms which are advantageous to the public welfare of the city. AS 29.10.132(c).[5] Since significant restrictions and controls are retained by the City of Palmer over Huskey Manufacturing Corporation's operations, the bond issue in question is not violative of AS 37.10.085. These controls and restrictions were imposed upon the corporation to insure the effectuation of the public purpose objective of this bond issue. Roe v. Kervick, 42 N.J. 191, 199 A.2d 834 (1964). We think that the question of whether the public credit is being pledged for a private purpose is also comprehended under the broader question of whether a public purpose is served by the bond issue and plan for its expenditure, which is discussed below.

IS THE PROJECT A CAPITAL IMPROVEMENT?

The contention is made that the indebtedness would violate Article IX, § 9, of the Alaska constitution[6] which requires that such debt can be incurred only for capital improvements. It is argued that in City of Juneau v. Hixson, 373 P.2d 743 (Alaska 1962), this court laid down a strict test of what constitutes a "capital improvement," rendering that term synonymous with "public works of a permanent character." Because an industrial development project is not clearly within that category, it is said that the plan before us must fail.

We do not read the *Hixson* case so narrowly. There we struck down a bond issue because no capital improvement would have resulted from the expenditure of the proceeds. The vice in the *Hixson* case was that raw land would have been acquired with the proceeds and would then have been donated to the State of Alaska as a proposed capitol site. As a result of the plan, the City of Juneau would have been left with no tangible asset in place of the indebtedness. Furthermore, the State of Alaska had entered into no agreement for and had not otherwise shown an interest in the acquisition or use of any capitol site.

[3] By contrast, in the case before us the City of Palmer will own a tangible asset. The plan is that the indebtedness shall be retired out of the rental money received over the life of the bond issue. The land and building fulfill the definition of "capital improvements" which was stated in the

4. Alaska Const., art. IX, § 6:
"Public Purpose. No tax shall be levied, or appropriation of public money made, or public property transferred, nor shall the public credit be used, except for a public purpose."
The courts which have upheld bonding projects as a legitimate exercise of power by the political subdivisions have held that a statute which pledges only project revenues does not pledge the public credit, and, therefore does not lend the public credit in aid of anyone. Newberry v. City of Andalusia, 257 Ala. 49, 57 So.2d 629 (1952); Wayland v. Snapp, 232 Ark. 77, 334 S.W.2d 623 (1960); Bennett v. City of Mayfield, 323 S.W.2d 573 (Ky.1959).

5. "City properties. * * *
(c) The council, in order to make sites available for new industries which will benefit the municipality, may likewise acquire, own and hold such sites, including real property, either inside or outside the corporate limits and may sell, lease or dispose of them upon the terms and conditions as it considers advantageous to the civic welfare of the city, to persons who will agree to install, maintain and operate a beneficial new industry. Sites acquired under this paragraph and any right, equity, claim or title acquired by the municipality to real property sold to it for delinquent taxes are not 'property acquired, owned or held for or devoted to a public use' as used herein."

6. Alaska Const., art. IX, § 9:
"Local Debts. No debt shall be contracted by any political subdivision of the State, unless authorized for capital improvements by its governing body and ratified by a majority vote of those qualified to vote and voting on the question."

AGO 560075

Hixson case[7] as being "associated with value represented by real or personal property in some form and with relative permanency." 373 P.2d, at 747. There is here no giving away of the asset. On the contrary, the city's real ownership of the structure should increase as the years of rental payment go by. Even if the tenants should default, the building probably would be susceptible to a number of other beneficial uses. We conclude, therefore, that the bond issue and the plan of expenditure does not violate the capital improvement requirement of our constitution.

IS THERE A FULFILLMENT OF PUBLIC PURPOSE?

Article IX, § 6, of the Alaska constitution provides that "[n]o tax shall be levied, or appropriation of public money made, or public property transferred, nor shall the public credit be used, except for a public purpose." It is asserted that the bond issue and the plan for its expenditure violates this provision.

In DeArmond v. Alaska State Development Corporation, 376 P.2d 717 (Alaska 1962), this court noted that the term "public purpose" is one of great imprecision. As we said there,

> "We believe that it would be a disservice to future generations for this court to attempt to define it. It is a concept which will change as changing conditions create changing public needs. Whether a public purpose is being served must be decided as each case arises and in the light of the particular facts and circumstances of each case." 376 P.2d at 721.

The technique used by most courts is that of looking to the entire factual and governmental context to determine whether a particular plan of action serves a public purpose.[8] In the area of industrial development bond issues, numerous decisions have upheld such plans.[9] There is much criticism which can be leveled against a community using its public borrowing capacity to sponsor or induce the location of private industry within its boundaries. Many of these plans have been attacked on grounds of public policy, but they have been sustained frequently by the courts.[10] It is true that such plans are susceptible to abuse. Municipalities have been known to go bankrupt after having induced an industry to come to them under such a plan.[11] There are dangers that an industry locating in a community may end up dominating the political and economic processes. On the

7. In City of Juneau v. Hixson, 373 P.2d 743 (Alaska 1962), this court defined "capital improvement" as follows:

> "The trial court was correct in holding that the bond issue herein was not for a capital improvement. Assuming for the moment that the expenditure of the money could accomplish the desired objective, the end product would lack most of the attributes usually associated with the completed public project for which general obligation bonds have been sold. No permanent asset in the form of real or personal property would accrue to the city. The property acquired by the proceeds would be donated to the state. No thing of value would remain the property of the city. No improvement of general use or service to the taxpayers of the city would have been created by the expenditure. No tangible security for the bonded indebtedness would have been created - in fact, the total security would have been reduced by the removal of some seven acres of downtown property from the city's tax rolls." 373 P.2d, at 748.

8. See Note, "Legal Limitations on Public Inducements to Industrial Location," 59 Colum.L.Rev. 618 (1959).

9. Newberry v. City of Andalusia, 257 Ala. 89, 57 So.2d 629 (1952); Wayland v. Snapp, 232 Ark. 57, 334 S.W.2d 622 (1960); Dyche v. City of London, 288 S.W.2d 678 (Ky.1956).

10. Although courts have split on the validity of revenue bond plans, the weight of authority is in their favor. Pinsky, "State Constitutional Limitations on Public Industrial Financing: An Historical and Economic Approach," 111 U. of Pa.L.Rev. 265, 276 n. 63 (1962).

11. Long run economic and social changes are ever present sources of financial risk. Population shifts or widespread economic recession may render unworkable fiscal policies that were once considered sound. These risks, however, are inevitable concomitants of public decision making.

AGO 560076

other hand, it is recognized that the location of an industry in a particular community may have widespread economic benefits and that these do fulfill the public purpose and the general welfare of the community, broadly conceived. The tendency in most of the modern case law is to broaden the notion of public purpose to include such projects as the one contemplated by the City of Palmer.[12]

In Walker v. Alaska State Mortgage Association, 416 P.2d 245 (Alaska 1966), and in Suber v. Alaska State Bond Committee, 414 P.2d 546 (Alaska 1966), such broad notions of public purpose were applied. As we observed in the *Suber* case,

> "The basic objective of government is to protect and promote the health, safety and general welfare of the people. When a condition of affairs appears in the state which presents a threat to the accomplishment of that objective, the government has the right, and the obligation, to cope with such threat by whatever measures, within constitutional limits, that are necessary or appropriate." 414 P.2d, at 551–552.

[4] The role of the courts in matters of this kind is relatively limited. Our function is not to determine whether, as prudent burghers, we might think this plan wise. City of Juneau v. Hixson, supra. The test which we must apply is whether the plan is so unreasonable as to transgress the limitations of our constitution. If the plan of action were plainly foolhardy, or if it amounted to the pledging of credit or the giving away of assets without any corresponding discernible benefit, we might be persuaded to strike down the plan. But that is not the case here.

[5] The benefits from the plan of the City of Palmer may be enjoyed in part by some individuals more than by others. But collective advantages to the community at large can be perceived quite readily. Although the development of industry is not always an unmixed blessing, as it may impose burdens upon other public facilities, it is hard to see how the City of Palmer could be hurt by the location of an industry within its boundaries. Its plight at the moment is that of an eroding economic community. If the city fathers and the voters of the community feel that this plan of action is necessary, it is not for us to retard them. It is within their legislative province to determine whether the advantages outweigh the risks.

Because we think the public purpose of the project has been demonstrated, we find the bond issue valid.

Affirmed.

12. In the cases applying the public purpose doctrine and the public aid limitations to the fields of transportation, recreation, and parking, courts have placed considerable emphasis on the public importance of the project and the urgency of the need for public financing. Plinsky, supra note 10.

ROBERT J. KUTAK
HAROLD L. ROCK
WILLIAM F. CAMPBELL
ALLAN JAY GARFINKLE
THOMAS A. WOODWARD
GLEN A. SUBRIDGE
RICHARD L. WEILL
JOHN E. NUSSELMAN
ALLACE H. JOHNSON
RICHARD A. SPELLMAN
STEVEN E. HUFF
GREGORY DuBOIS ERWIN
THOMAS J. McCUSKER
GEORGE H. KRAUSS
MAUREEN E. McGRATH
HUGH W. McNULTY, JR.
KENNETH J. STUART
DICK W. [illegible]
ANGELO P. PARKER
J. MICHAEL GOTTSCHALK
KENNETH E. ILTZ
JAMES C. LAUNDEL
JOHN J. WAGNER
DONALD A. KRESS
DANIEL E. MUROWITZ
PAUL R. TUFT
RICHARD T. PFEIFER
GREGORY W. SEARSON
JOHN E. HUBBARD
HARRY D. DIXON, JR.
JOE E. ARMSTRONG
WILLIAM E. HOLLAND
RICHARD D. CIMINO
GARETH G. MORRIS
RAVEN V. P. BELL
PAUL D. LUCO
JOEL T. BOEHM
TERRENCE J. FERGUSON
J. GREGORY M. EDEN
LARRY L. CARLILE
SARAH J. PENN

LAUREN M. RONALD
PATRICIA J. WINTER
LINDSEY MILLER LERMAN
JOYCE A. DIXON
DIANNE L. STODDARD
TIMOTHY J. KINCAID
JOHN C. MINAHAN, JR.
FRED M. GREGURAS
PAUL E. BELITZ
DENIS P. BURKE
SCOTT C. HOYT
DANIEL S. REYNOLDS
DAVID J. JACOBSON
P. THOMAS POGGE
J. THOMAS MARTEN
D. CHARLES SHOEMAKER
KENNETH R. DOODS
WALTER L. GRIFFITHS
THOMAS B. HOLLEY
JO E. BASS
FRANK A. TAYLOR
RANDALL R. ELEY
CURTIS L. CHRISTENSEN
MICHAEL I. CURRY
LOREN E. DOSSONVILLE
DAWN R. DUVEN
JANE ERDENBERGER
FELICIA C. FLOWERS
LYNNE A. FRIEDEWALD
DENNIS L. HOLSAPPLE
FRANK M. SCHEPERS
JULIA G. GINSBURG
CLIFTON R. JESSUP, JR.
DAVID A. GARDELS
CHRISTIAN I. HALABI
JEDD S. PALMER
SHEILA A. PHILLIPS
MOLLY M. ROMERO
PATRICIA A. SCHUETT
STEVEN W. SELINE
JUDY A. WEILL
DENNIS B. WILSON

THE OMAHA BUILDING
1650 FARNAM STREET
OMAHA, NEBRASKA 68102
(402) 346 6000

OMAN L. KRUSKA
WILLIAM GROSINSKY
FRANK L. SUBRIDGE
GAIL E. SUBRIDGE
COUNSEL

ATLANTA
1800 STANDARD FEDERAL SAVINGS BUILDING
ATLANTA GEORGIA 30303
404 522-6700

DENVER
1330 COLORADO NATIONAL BUILDING
DENVER, COLORADO 80202
303 534-1330

MINNESOTA
4644 IDS TOWER
MINNEAPOLIS, MINNESOTA 55402
612 338-1690

WASHINGTON
1101 CONNECTICUT AVENUE, N.W.
WASHINGTON, D.C. 20036
202 828-2400

December 14, 1979

Dr. Robert LeResche
Commissioner of Natural Resources
Pouch "M"
Juneau, Alaska 99801

Re: Issuance of Revenue Bonds
by the City of Valdez, Alaska

Dear Dr. LeResche:

Concern has been expressed as to whether Section 37.10.085 of the Alaska Statutes would be violated if the City of Valdez, Alaska, issues its revenue bonds (the "Bonds") and the proceeds thereof were made available for the acquisition and construction of certain economic development facilities and other facilities for general public use necessary for the petroleum refinery to be built by The Alpetco Company ("Alpetco") in the City.

Section 37.10.085 states:

Neither the state nor a political subdivision of the state may

(1) Make a subscription to the capital stock of a corporation;

(2) Lend its credit for use of a corporation; or
(3) Borrow money for the use of a corporation.

This section was discussed in Wright v. City of Palmer, 468 P2d. 326 (Alaska 1970), which involved an issue of general obligation bonds by the City of Palmer to finance manufacturing facilities for Huskey Manufacturing Corporation and the lease of such facilities to Huskey. The Court found that the bond issue did not violate AS §37.10.085 in that no money was being handed directly to the corporation, nor was the City pledging its credit or taxing power to make good the indebtedness of a private person. The Court did not find unreasonable the determination of the City that the facilities were to serve a public purpose.

Because the Wright decision involved general obligation bonds it is very strong authority to the effect that the issuance of revenue bonds by the City of Valdez for facilities to be used by a private corporation would not violate §37.10.085. The Alaska Supreme Court recognized in Wright the theory that a statute which pledges only project revenues does not pledge the public credit and therefore does not lend the public credit in aid of anyone. This confirms the position of the Supreme Court in De Armond v. Alaska State Development Corporation, 376 P2d. 717 (Alaska 1962) wherein the Court held that the Alaska State Development Corporation could borrow funds to aid in industrial development. The primary theory in upholding this power was that the credit of the state was not pledged and therefore no public funds or credit were involved.

This is further made clear by Section 11 of Article IX of the Alaska Constitution which states:

> The restrictions on contracting debt do not apply to debt incurred through the issuance of revenue bonds by a public enterprise or public corporation of the State or a political subdivision, when the only security is the revenues of the enterprise or corporation. The

restrictions do not apply to indebtedness to be paid from special assessments on the benefited property, nor do they apply to refunding indebtedness of the State or its political subdivisions.

Based on our review of the Constitution, statutes and case law of the State of Alaska, we are of the opinion that the issuance of the Bonds as contemplated by Resolution No. 7953 of the City of Valdez would not be in violation of §37.10.085 of the Alaska Statutes.

Kutak Rock & Huie

ALASKA INTERSTATE COMPANY
P. O. Box 6554
HOUSTON, TEXAS 77005

O. CHARLES HONIG
CHAIRMAN OF THE BOARD

December 14, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, Alaska Interstate Company, is a 75.45% shareholder of Alaska Petrochemical Company which is a partner in The Alpetco Company ("Alpetco"). Alpetco was established as of October 1, 1979, to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between the State of Alaska and Alaska Petrochemical Company. Alaska Petrochemical Company has made certain commitments today to Alpetco to provide assurances to the Commissioner of Natural Resources of the State of Alaska (the "Commissioner") that at least $23.4 million in Total Project Costs (as defined in the Royalty Oil Contract) actually will have been expended by a certain date. The other partners in Alpetco have provided similar commitments in respect of an additional $76.6 million in expenditures.

To provide further assurances to the Commissioner, the undersigned commits that if, and to the extent, Alaska Petrochemical Company should fail, in whole or in part, to fulfill Alaska Petrochemical Company's commitment relating to expenditures in accordance with its terms, the undersigned hereby commits to fulfill at least its pro rata share of such commitment, and if needed, hereby commits to fulfill all of Alaska Petrochemical Company's commitment hereunder.

The above commitment of the undersigned is made, with similar commitments by the shareholders of the partners in Alpetco other than Alaska Petrochemical Company, solely for the purpose of providing the Commissioner assurances that at least $100 million in Total Project Costs actually will have been expended prior to the time crude oil is available to the State of Alaska for delivery to Alpetco under the Royalty Oil Contract.

This letter replaces our letter on this same subject which was dated December 13, 1979.

Yours very truly,

ALASKA INTERSTATE COMPANY

O. Charles Honig

AGO 560081

ALASKA PETROCHEMICAL COMPANY
3700 BUFFALO SPEEDWAY
HOUSTON, TEXAS 77098
TELEPHONE 713 840-1243 TELEX 791461

December 18, 1979

Dr. Robert E. LeResche
Commissioner
Department of Natural Resources
Pouch "M"
Juneau, Alaska 99811

HAND DELIVER

Re: Agreement for the Sale and Purchase of State Royalty Oil between Alaska Petrochemical Company and the State of Alaska dated February 22, 1978

Progress Report #18

Dear Commissioner LeResche:

Pursuant to Article 4.2.3 of the above referenced Agreement (the "Agreement"), Buyer's Progress Report for the month ending November 30, 1979 is as follows:

1. Compliance with Article 10.2 of the Agreement:

Although this Progress Report No. 18 covers the month ending November, 1979, Alpetco delivered letters, reports, and other documents to the Commissioner of Natural Resources on December 13, 1979 in support of Alpetco's compliance with Article 10.2(3)(a)-(h) of the Agreement. Such material was hand delivered to the Commissioner and the State's advisors in Seattle, Washington.

In addition to the material submitted to the Commissioner on December 13, 1979, Alpetco is today submitting supplemental material in further support of Alpetco's compliance with Article 10.2(3)(d) and (e) of the Agreement. Such material is attached hereto and enclosed by reference.

601 WEST 5TH AVENUE ANCHORAGE, ALASKA 99501, TELEPHONE 907 272-1517, TELEX 090-25157

2. Engineering, Design and Construction:

During November, engineering work continued in support of the project's December 18 contract "benchmark" requirements.

On November 19, 1979 Alpetco submitted to the Commissioner and Mr. Thomas Cook, Director of Division of Minerals and Energy Management, copies of all material state, local and federal permit applications as outlined in Commissioner LeResche's letter to Gordon Cain dated September 27, 1979.

On December 7, 1979, the Alpetco Draft Environmental Impact Statement and Appendices were published in the Federal Record.

On December 7, 1979, Alpetco signed an Engineering Construction Contract with Thyssen Rheinstahl Technik GmbH of Dusseldorf, West Germany and Foster Wheeler Energy Corporation of Linden, New Jersey. Under the terms of this agreement, Thyssen and Foster Wheeler will provide Alpetco with a fixed price for the construction of the refinery and in addition will give Alpetco a completion and performance guarantee for the project. Thyssen and Foster Wheeler will be the prime contractor for the project.

No construction activities took place during the month of November or during the first part of December, 1979.

3. Marketing:

Charter Oil (Alaska), Inc. has entered into an agreement with The Alpetco Company, a joint venture partnership of Alaska Petrochemical Company, Charter Oil (Alaska), Inc. and E. F. Hutton (Alaska) Inc. to purchase 70% of the output of the Valdez facility. This contract is effective December 1, 1979.

4. Financing and Expenditures:

During the month of November and early part December, 1979

The Company obtained financing commitments for the project in the aggregate of $1.7 billion.

On November 19, 1979 the City of Valdez, Alaska unanimously passed Ordinance 7917 authorizing the City to issue tax exempt industrial revenue bonds to finance the Alpetco project. Also, on November 19, 1979, the City Council of Valdez unanimously passed Resolution 7953 authorizing the Mayor of Valdez to execute a commitment to lend Alpetco $600,000,000 from the proceeds of the sale of tax exempt industrial revenue bonds. To support this commitment, the City of Valdez has obtained and underwriting commitment, dated November 19, 1979 from E. F. Hutton & Company to purchase $600,000,000 of the tax exempt bonds.

On December 7, 1979 in consideration of Alpetco entering into the aforementioned engineering and construction contract with Thyssen Rheinstahl Technik GmbH and Foster Wheeler Energy Corporation, Thyssen Rheinstahl Technik delivered a letter committing Thyssen to arrange financing of up to $750,000,000 to cover the cost for the engineering, equipment, materials, construction and other services required for the project.

By letters dated December 13, 1979 the partners of The Alpetco Company have committed, subject to certain conditions, to contribute in the aggregate $350,000,000 in equity to the Alpetco project.

Sincerely,

Gordon A. Cain

Gordon A. Cain
President

GAC/my

cc: Mr. Thomas K. Williams, Commissioner of Revenue (Juneau)
Mr. Thomas Cook, Director Division of Minerals and Energy Management (Anchorage)
Mr. Ed Park, Division of Minerals and Energy Management (Anchorage)

THE ALPETCO COMPANY
3700 BUFFALO SPEEDWAY
HOUSTON, TEXAS 77098
TELEPHONE 713 840-1243 TELEX 791461

December 13, 1979

Dr. Robert E. LeResche
Commissioner of Natural Resources
State of Alaska
Pouch "M"
Juneau, Alaska 99801

Dear Commissioner LeResche:

The Alpetco Company, a joint venture partnership ("Alpetco") established as of October 1, 1979, by Charter Oil (Alaska), Inc., Alaska Petrochemical Company and E. F. Hutton (Alaska), Inc. (collectively, the "Partners") to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between Alaska Petrochemical Company and the State of Alaska has, in our opinion, satisfied the benchmark provisions of Section 10.2(3) of the Royalty Oil Contract.

Assuming that you concur, we respectfully request that you confirm to us in writing that the provisions of Section 10.2(3) of the Royalty Oil Contract have been satisfied, and that you will give notice to the Lessees (as defined in the Royalty Oil Contract) as soon as practicable but not later than January 18, 1980, pursuant to Section 2.2 of the Royalty Oil Contract, exercising the State of Alaska's right to take its royalty oil in kind, up to 150,000 barrels per day, for sale to The Alpetco Company pursuant to the terms of the Royalty Oil Contract.

In connection with our request to initiate deliveries to us of royalty crude oil beginning July 18, 1980, we are providing with this letter commitments of the Partners that $100 million in Total Project Costs (as defined in the Royalty Oil Contract) will actually be expended within six (6) months following the date on which you give notice to the Lessees of the State's election to take royalty oil in kind for sale to us. In addition, at your request, we are also providing you a letter dated December 12, 1979 setting forth how Alpetco expects that the $100 million will be spent.

Sincerely,

THE ALPETCO COMPANY

By Gordon A Cain
Gordon A. Cain, President

601 WEST 5TH AVENUE, ANCHORAGE, ALASKA 99501, TELEPHONE 907 272-1517, TELEX 090-25157

CHARTER OIL (ALASKA), INC.
208 Laura Street
Jacksonville, Florida 32201
904/358-4395

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, Charter Oil (Alaska), Inc., is a 70.0% partner in The Alpetco Company ("Alpetco"). Alpetco, a joint venture partnership, was established as of October 1, 1979 by Charter Oil (Alaska), Inc., Alaska Petrochemical Company and E. F. Hutton (Alaska) Inc. (collectively, the "Partners") to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between Alaska Petrochemical Company and the State of Alaska.

Alpetco has today by letter addressed to the Commissioner of Natural Resources of the State of Alaska (the "Commissioner") notified the Commissioner of Alpetco's compliance with the benchmark provisions of Section 10.2(3) of the Royalty Oil Contract and of its request for the Commissioner to take the appropriate steps to initiate deliveries to Alpetco of crude oil in July, 1980, pursuant to the terms of the Royalty Oil Contract. Under the Royalty Oil Contract, in order for Alpetco to be entitled to delivery of crude oil, $100 million in Total Project Costs (as defined in the Royalty Oil Contract) must first actually have been expended.

The Partners have determined that in order to provide assurances to the Commissioner that at least $100 million in the expenditures for Total Project Costs will be made prior to crude oil deliveries, it would be desirable for the Partners to commit to the Commissioner pro rata in accordance with their partnership interest that such expenditures will be made.

Accordingly, the undersigned commits that by the date (the "Expenditure Date") which is six (6) months following the date on which the Commissioner gives notice to the Lessees (as defined in the Royalty Oil Contract) of the election of the State of Alaska to take royalty oil in kind

for sale to Alpetco, the undersigned will actually expend in Total Project Costs 70.0% of the excess, if any, of $100 million over the amount actually expended in Total Project Costs prior to the Expenditure Date, not to exceed $70,000,000, provided each of the other Partners performs its similar commitment pro rata in accordance with its partnership interest. The commitment of the undersigned hereunder is subject only to the Royalty Oil Contract remaining in effect with Alpetco entitled to the rights of "Buyer" thereunder and to the absence of any statute, rule or order of any governmental or judicial authority which prohibits or prevents, or any governmental or judicial action or proceeding which seeks to prohibit or prevent Alpetco from exercising the rights of "Buyer" under the Royalty Oil Contract.

The above commitment of the undersigned is made, with similar commitments of the other Partners, solely for the purpose of providing the Commissioner assurances that at least $100 million in Total Project Costs actually will have been expended prior to the time crude oil is available to the State of Alaska for delivery to Alpetco under the Royalty Oil Contract.

Attached hereto is a commitment by the sole shareholder of the undersigned in support of the above commitment.

Very truly yours,

CHARTER OIL (ALASKA), INC.

By _____

The Charter Company
208 Laura Street · Post Office Box 2017
Jacksonville, Florida 32231
Telephone 904-358-4111 · Telex 56-239

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speeedway
Houston, Texas 77098

Dear Sirs:

The undersigned, The Charter Company, is the 100% shareholder of Charter Oil (Alaska), Inc. which is a partner in The Alpetco Company ("Alpetco"). Alpetco was established as of October 1, 1979, to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between the State of Alaska and Alaska Petrochemical Company. Charter Oil (Alaska), Inc. has made certain commitments today to Alpetco to provide assurances to the Commissioner of Natural Resources of the State of Alaska (the "Commissioner") that at least $70.0 million in Total Project Costs (as defined in the Royalty Oil Contract) actually will have been expended by a certain date. The other partners in Alpetco have provided similar commitments in respect of an additional $30.0 million in expenditures.

To provide further assurances to the Commissioner, the undersigned commits that if, and to the extent, Charter Oil (Alaska), Inc. should fail, in whole or in part, to fulfill Charter Oil (Alaska), Inc.'s commitment relating to expenditures in accordance with its terms, the undersigned shall fulfill such commitment.

The above commitment of the undersigned is made, with similar commitments by the shareholders of the partners in Alpetco other than Charter Oil (Alaska), Inc., solely for the purpose of providing the Commissioner assurances that at least $100 million in Total Project Costs actually will have been expended prior to the time crude oil is available to the State of Alaska for delivery to Alpetco under the Royalty Oil Contract.

Yours very truly,

THE CHARTER COMPANY

By _____

ALASKA PETROCHEMICAL COMPANY
3700 BUFFALO SPEEDWAY
HOUSTON, TEXAS 77098
TELEPHONE 713 840-1243 TELEX 791461

December 13, 1979

The Alpetco Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, Alaska Petrochemical Company, is a 23.4% partner in The Alpetco Company ("Alpetco"). Alpetco, a joint venture partnership, was established as of October 1, 1979 by Charter Oil (Alaska), Inc., Alaska Petrochemical Company and E. F. Hutton (Alaska) Inc. (collectively, the "Partners") to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between Alaska Petrochemical Company and the State of Alaska.

Alpetco has today by letter addressed to the Commissioner of Natural Resources of the State of Alaska (the "Commissioner") notified the Commissioner of Alpetco's compliance with the benchmark provisions of Section 10.2(3) of the Royalty Oil Contract and of its request for the Commissioner to take the appropriate steps to initiate deliveries to Alpetco of crude oil in July, 1980, pursuant to the terms of the Royalty Oil Contract. Under the Royalty Oil Contract, in order for Alpetco to be entitled to delivery of crude oil, $100 million in Total Project Costs (as defined in the Royalty Oil Contract) must first actually have been expended.

The Partners have determined that in order to provide assurances to the Commissioner that at least $100 million in the expenditures for Total Project Costs will be made prior to crude oil deliveries, it would be desirable for the Partners to commit to the Commissioner pro rata in accordance with their partnership interest that such expenditures will be made.

Accordingly, the undersigned commits that by the date (the "Expenditure Date") which is six (6) months following the date on which the Commissioner gives notice to the Lessees (as defined in the Royalty Oil Contract) of the election of the State of Alaska to take royalty oil in kind for sale to Alpetco, the undersigned will actually expend in

AGO 560089

Total Project Costs 23.4% of the excess, if any, of $100 million over the amount actually expended in Total Project Costs prior to the Expenditure Date, not to exceed $23,400,000, provided each of the other Partners performs its similar commitment pro rata in accordance with its partnership interest. The commitment of the undersigned hereunder is subject only to the Royalty Oil Contract remaining in effect with Alpetco entitled to the rights of "Buyer" thereunder and to the absence of any statute, rule or order of any governmental or judicial authority which prohibits or prevents, or any governmental or judicial action or proceeding which seeks to prohibit or prevent Alpetco from exercising the rights of "Buyer" under the Royalty Oil Contract.

The above commitment of the undersigned is made, with similar commitments of the other Partners, solely for the purpose of providing the Commissioner assurances that at least $100 million in Total Project Costs actually will have been expended prior to the time crude oil is available to the State of Alaska for delivery to Alpetco under the Royalty Oil Contract.

Attached hereto are commitments by the principal shareholders of the undersigned in support of the above commitment.

Very truly yours,

ALASKA PETROCHEMICAL COMPANY

By Gordon A Cain

ALASKA INTERSTATE COMPANY
P. O. Box 6554
HOUSTON, TEXAS 77005

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, Alaska Interstate Company, is a 75.45% shareholder of Alaska Petrochemical Company which is a partner in The Alpetco Company ("Alpetco"). Alpetco was established as of October 1, 1979, to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between the State of Alaska and Alaska Petrochemical Company. Alaska Petrochemical Company has made certain commitments today to Alpetco to provide assurances to the Commissioner of Natural Resources of the State of Alaska (the "Commissioner") that at least $23.4 million in Total Project Costs (as defined in the Royalty Oil Contract) actually will have been expended by a certain date. The other partners in Alpetco have provided similar commitments in respect of an additional $76.6 million in expenditures.

To provide further assurances to the Commissioner, the undersigned commits that if, and to the extent, Alaska Petrochemical Company should fail, in whole or in part, to fulfill Alaska Petrochemical Company's commitment relating to expenditures in accordance with its terms, the undersigned shall fulfill its pro rata share of such commitment.

The above commitment of the undersigned is made, with similar commitments by the shareholders of the partners in Alpetco other than Alaska Petrochemical Company, solely for the purpose of providing the Commissioner assurances that at least $100 million in Total Project Costs actually will have been expended prior to the time crude oil is available to the State of Alaska for delivery to Alpetco under the Royalty Oil Contract.

Yours very truly,

ALASKA INTERSTATE COMPANY

By O. Charles Hanig

E.F. HUTTON (ALASKA) INC.
One Battery Park Plaza
New York, New York 10004
212/742-5000

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, E.F. Hutton (Alaska) Inc., is a 6.6% partner in The Alpetco Company ("Alpetco"). Alpetco, a joint venture partnership, was established as of October 1, 1979 by Charter Oil (Alaska), Inc., Alaska Petrochemical Company and E.F. Hutton (Alaska) Inc. (collectively, the "Partners") to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between Alaska Petrochemical Company and the State of Alaska.

Alpetco has today by letter addressed to the Commissioner of Natural Resources of the State of Alaska (the "Commissioner") notified the Commissioner of Alpetco's compliance with the benchmark provisions of Section 10.2(3) of the Royalty Oil Contract and of its request for the Commissioner to take the appropriate steps to initiate deliveries to Alpetco of crude oil in July, 1980, pursuant to the terms of the Royalty Oil Contract. Under the Royalty Oil Contract, in order for Alpetco to be entitled to delivery of crude oil, $100 million in Total Project Costs (as defined in the Royalty Oil Contract) must first actually have been expended.

The Partners have determined that in order to provide assurances to the Commissioner that at least $100 million in the expenditures for Total Project Costs will be made prior to crude oil deliveries, it would be desirable for the Partners to commit to the Commissioner pro rata in accordance with their partnership interest that such expenditures will be made.

Accordingly, the undersigned commits that by the date (the "Expenditure Date") which is six (6) months following the date on which the Commissioner gives notice to the Lessees (as defined in the Royalty Oil Contract) of the election of the State of Alaska to take royalty oil in kind for sale to Alpetco, the undersigned will actually expend in Total Project Costs 6.6% of the excess, if any, of $100 million over the

amount actually expended in Total Project Costs prior to the Expenditure Date, not to exceed $6,600,000, provided each of the other Partners performs its similar commitment pro rata in accordance with its partnership interest. The commitment of the undersigned hereunder is subject only to the Royalty Oil Contract remaining in effect with Alpetco entitled to the rights of "Buyer" thereunder and to the absence of any statute, rule or order of any governmental or judicial authority which prohibits or prevents, or any governmental or judicial action or proceeding which seeks to prohibit or prevent Alpetco from exercising the rights of "Buyer" under the Royalty Oil Contract.

The above commitment of the undersigned is made, with similar commitments of the other Partners, solely for the purpose of providing the Commissioner assurances that at least $100 million in Total Project Costs actually will have been expended prior to the time crude oil is available to the State of Alaska for delivery to Alpetco under the Royalty Oil Contract.

Attached hereto is the commitment by the sole shareholder of the undersigned in support of the above commitment.

Very truly yours,

E.F. HUTTON (ALAKSA) INC.

By _____

EF Hutton

One Battery Park Plaza
New York, N.Y. 10004
Telephone (212) 742-5000

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, The E. F. Hutton Group Inc., is a 100% shareholder of E. F. Hutton (Alaska) Inc. which is a partner in The Alpetco Company ("Alpetco"). Alpetco was established as of October 1, 1979, to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between the State of Alaska and Alaska Petrochemical Company. E. F. Hutton (Alaska) Inc. has made certain commitments today to Alpetco to provide assurances to the Commissioner of Natural Resources of the State of Alaska (the "Commissioner") that at least $6.6 million in Total Project Costs (as defined in the Royalty Oil Contract) actually will have been expended by a certain date. The other partners in Alpetco have provided similar commitments in respect of an additional $93.4 million in expenditures.

To provide further assurances to the Commissioner, the undersigned commits that if, and to the extent, E. F. Hutton (Alaska) Inc. should fail, in whole or in part, to fulfill E. F. Hutton (Alaska) Inc.'s commitment relating to expenditures in accordance with its terms, the undersigned shall fulfill such commitment.

The above commitment of the undersigned is made, with similar commitments by the shareholders of the partners in Alpetco other than E. F. Hutton (Alaska) Inc., solely for the purpose of providing the Commissioner assurances that a least $100 million in Total

EF Hutton

Project Costs actually will have been expended prior to the time crude oil is available to the State of Alaska for delivery to Alpetco under the Royalty Oil Contract.

Yours very truly,

THE E. F. HUTTON GROUP INC.

By _____

Seatrain Lines, Inc.

Howard M. Pack
Vice Chairman of the Board

1 Chase Manhattan Plaza
New York, New York 10005

Phone: (212) 964-3400
Telex:
International: 232740 (RCA)
421225 (ITT)
Domestic: 710-581-2334 (TWX)
127-396 (WU)
Cables: SHIPTRAMP or OSTCORPO

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, Seatrain Lines, Inc. is the owner of 100% of Barbour Oil Company, which is a 22.12% shareholder of Alaska Petrochemical Company which is a partner in The Alpetco Company ("Alpetco"). Alpetco was established as of October 1, 1979, to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between the State of Alaska and Alaska Petrochemical Company. Alaska Petrochemical Company has made certain commitments today to Alpetco to provide assurances to the Commissioner of Natural Resources of the State of Alaska (the "Commissioner") that as least $23.4 million in Total Project Costs (as defined in the Royalty Oil Contract actually will have been expended by a certain date. The other partners in Alpetco have provided similar commitments in respect of an additional $76.6 million in expenditures.

To provide further assurances to the Commissioner, the undersigned commits that if, and to the extent, Alaska Petrochemical Company should fail, in whole or in part, to fulfill Alaska Petrochemical Company's commitment relating to expenditures in accordance with its terms, the undersigned shall fulfill its pro rata share of such commitment.

The above commitment of the undersigned is made, with similar commitments by the shareholders of the partners in Alpetco other than Alaska Petrochemical Company, solely for the purpose of providing the Commissioner assurances that at least $100 million in Total Project Costs actually will have been expended prior to the time crude oil is available to the State of Alaska for delivery to Alpetco under the Royalty Oil Contract.

Yours very truly,
SEATRAIN LINES, INC.

By _____

AGO 560096

ALASKA PETROCHEMICAL COMPANY
3700 BUFFALO SPEEDWAY
HOUSTON, TEXAS 77098
TELEPHONE 713 840-1243 TELEX 791461

December 12, 1979

Dr. Robert E. LeResche, Commissioner
Department of Natural Resources
State of Alaska
Pouch M
Juneau, Alaska 99811

Dear Commissioner LeResche:

According to the provisions of our Royalty Oil Contract as amended, Alpetco may purchase royalty crude oil only after 25 months have passed from the Effective Date and $100,000,000 has been expended in Total Project Costs.

The purpose of this letter is to assure you that the $100,000,000 will be spent timely so that notice will be given to the North Slope Producers in time for Alpetco to purchase the royalty crude oil immediately after 25 months have passed from the Effective Date.

The $100,000,000 will be spent in the following manner:

1. The Total Project Costs for administration, engineering, legal and environmental permitting by July 1, 1980, will exceed $25,000,000.

2. As soon as the weather allows and the necessary permits have been issued, we will start site preparation in Valdez. This will involve clearing and leveling the site, building roads and bridges, putting in dykes and drainage ditches, and building or rehabilitating the wharf to unload equipment. The total amount we expect to spend in 1980 for these purposes is $30,000,000. If we are able to start work by May 1, 1980, we expect to spend $2,600,000 of this by July 1, 1980.

3. We will spend an additional amount for one or more of the purposes listed below such that the sum of the amount spent hereunder plus the amounts spent under No. 1 and No. 2 above will exceed $100,000,000:

    a. Order and pay for long delivery items such as compressors, turbines, and electrical equipment.

601 WEST 5TH AVENUE ANCHORAGE, ALASKA 99501, TELEPHONE 907 272-1517, TELEX 090-25157

b. Order and pay for steel to be used in fabricating process equipment, tanks, and structures for the facility.

c. Buy a construction camp.

Attached are letters from the owners of Alpetco committing the $100,000,000 required to carry out the above program.

Very truly yours,

ALASKA PETROCHEMICAL COMPANY

By Gordon A Cain
Gordon A. Cain, President

ALASKA PETROCHEMICAL COMPANY
3700 BUFFALO SPEEDWAY
HOUSTON, TEXAS 77098
TELEPHONE 713 840-1243 TELEX 791461

December 13, 1979

Dr. Robert E. LeResche
Commissioner of Natural Resources
Pouch "M"
Juneau, Alaska 99801

Dear Commissioner LeResche:

When negotiating the terms of its Royalty Oil Contract with the State of Alaska some two years ago, Alaska Petrochemical Company insisted on a right to begin purchasing the royalty oil prior to the time of plant start-up. As you know, we held out for this right so that we could have this crude processed into products we would eventually make in Alaska and thus begin developing market channels for them. We also maintained that we needed the opportunity to benefit from interim crude transactions in order to help the economics of building a large plant in Alaska.

While the Royalty Oil Contract does not require us to do so, we have maintained all along that profits realized from the sale or processing of the crude prior to plant start-up could be critical to the success of the project.

It is therefore with great pleasure that I attach hereto letters from the individual partners of Alpetco representing a commitment to reinvest such profits as required for equity in Alpetco.

Sincerely,

Gordon A. Cain

Gordon A. Cain
President

GAC/my

601 WEST 5TH AVENUE, ANCHORAGE, ALASKA 99501, TELEPHONE 907 272-1517, TELEX 090-25157

AGO 560099

ALASKA PETROCHEMICAL COMPANY
3700 BUFFALO SPEEDWAY
HOUSTON, TEXAS 77098
TELEPHONE 713 840-1243 TELEX 791461

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, Alaska Petrochemical Company, is a 23.4% partner in The Alpetco Company ("Alpetco"). Alpetco, a joint venture partnership, was established as of October 1, 1979, by the undersigned, Charter Oil (Alaska), Inc. and E. F. Hutton (Alaska) Inc. (collectively, the "Partners") to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between Alaska Petrochemical Company and the State of Alaska.

While not required by the terms of the Royalty Oil Contract, Alaska Petrochemical Company hereby agrees to leave in Alpetco or contribute to Alpetco an amount equal to Alaska Petrochemical Company's net profits resulting from the sale and/or processing of interim crude oil by Alpetco, as required for Alaska Petrochemical Company's equity in Alpetco.

Sincerely,

ALASKA PETROCHEMICAL COMPANY

By Gordon A Cain

601 WEST 5TH AVENUE, ANCHORAGE, ALASKA 99501, TELEPHONE 907 272-1517, TELEX 090-25157

CHARTER OIL (ALASKA), INC.
P. O. Box 4726
Jacksonville, Florida 32201
904/358-4395

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, Charter Oil (Alaska), Inc. is a 70.0% partner in The Alpetco Company ("Alpetco"). Alpetco, a joint venture partnership, was established as of October 1, 1979, by the undersigned, Alaska Petrochemical Company and E. F. Hutton (Alaska) Inc. (collectively, the "Partners") to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between Alaska Petrochemical Company and the State of Alaska.

While not required by the terms of the Royalty Oil Contract, Charter Oil (Alaska), Inc. hereby agrees to leave in Alpetco or contribute to Alpetco an amount equal to Charter Oil (Alaska), Inc.'s net profits resulting from the sale and/or processing of interim crude oil by Alpetco, as required for Charter Oil (Alaska), Inc.'s equity in Alpetco.

Sincerely,

CHARTER OIL (ALASKA), INC.

By

E. F. HUTTON (ALASKA) INC.
One Battery Park Plaza
New York, New York 10004
212/742-5000

December 13, 1979

The Alpetco Company
c/o Alaska Petrochemical Company
3700 Buffalo Speedway
Houston, Texas 77098

Dear Sirs:

The undersigned, E. F. Hutton (Alaska) Inc., is a 6.6% partner in The Alpetco Company ("Alpetco"). Alpetco, a joint venture partnership, was established as of October 1, 1979, by the undersigned, Alaska Petrochemical Company and Charter Oil (Alaska), Inc. (collectively, the "Partners") to receive an assignment of the rights and to assume the obligations of Alaska Petrochemical Company under the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, and amended May 17, 1978 (the "Royalty Oil Contract"), between Alaska Petrochemical Company and the State of Alaska.

While not required by the terms of the Royalty Oil Contract, E. F. Hutton (Alaska) Inc. hereby agrees to leave in Alpetco or contribute to Alpetco an amount equal to E. F. Hutton (Alaska) Inc.'s net profits resulting from the sale and/or processing of interim crude oil by Alpetco, as required for E. F. Hutton (Alaska) Inc.'s equity in Alpetco.

Sincerely,

E. F. HUTTON (ALASKA) INC.

By _____

PLEASE NOTE: THE PRECEDING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

ALASKA PETROCHEMICAL COMPANY

Alaska Royalty Crude Oil Contract
February 22, 1978

INDEX

A Agreement for the Sale and Purchase of State Royalty Oil between Alaska Petrochemical Company and the State of Alaska dated February 22, 1978

B Amendment dated May 17, 1978 to the Agreement for the sale and Purchase of State Royalty Oil

C State of Alaska Legislative Resolution No. 42 Approving the Sale of Royalty Oil to Alaska Petrochemical Company

AGREEMENT FOR THE SALE AND PURCHASE

OF

STATE ROYALTY OIL

ALASKA PETROCHEMICAL COMPANY
an Alaska corporation

THE STATE OF ALASKA
Department of Natural Resources

February 22, 1978

TABLE OF CONTENTS

ARTICLE		PAGE
	Preamble	1
I	Definitions	2
	1.1 Affiliate	2
	1.2 Commissioner	2
	1.3 Date of First Delivery	2
	1.4 Day	2
	1.5 Effective Date	3
	1.6 Force Majeure	3
	1.7 Leases or Lease Contracts	3
	1.8 Lessee	3
	1.9 Month	3
	1.10 Oil or Crude Oil	3
	1.11 Point of Delivery	3
	1.12 Petrochemical Facility	3
	1.13 Total Project Costs	3
II	Quantity Purchased and Sold	4
	2.1 Sale of Prudhoe Bay Royalty Oil	4
	2.2 Initiation of First Delivery	6
	2.3 Certain Future Sales of Oil Taken in Kind by Seller	6
	2.4 Buyer Option in the Event Certain Quantities Not Delivered	8
	2.5 Increases or Decreases of Crude Oil	11
	2.6 Delivery of TAPS Fill by Seller	12
III	Point of Delivery and Passage of Title	12
	3.1 Point of Delivery	12
	3.2 Passage of Title	13
	3.3 Buyer's Responsibility	13
IV	Representations and Obligations of Buyer	13
	4.1 Good Standing	13
	4.2 Construction of a Petrochemical Facility in the State of Alaska	13
	4.2.1 Construction Obligations	14
	4.2.2 Siting of Petrochemical Facility ..	14

ARTICLE		PAGE
	4.2.3 Progress Reports by Buyer ...	15
	4.3 Production of Energy Fuels for Intra-state Use	16
	4.4 Establishment of Charitable Foundation	16
V	Representations and Obligations of Seller .	18
	5.1 Seller's Royalty Oil	18
	5.2 Title	18
	5.3 Storage of Oil	19
	5.4 Covenant to Aid in Obtaining Governmental Permits	20
	5.5 Delivery of Information to Buyer	20
VI	Quality	22
	6.1 Standard	22
VII	Measurements and Tests	22
	7.1 Testing Standards and Procedures	22
	7.2 Delivery of Crude Oil Samples by Seller	23
VIII	Price	24
	8.1 Price	24
	8.1.1 Price of Oil Delivered Out of the Leases	24
	8.1.2 Price of Oil Sold Under Article 2.3	25
	8.1.3 Price of Oil Sold Under Article 2.4	25
	8.2 Reimbursement of Certain Costs of Seller	26
	8.3 Minimum Taking in Value by Seller	26
	8.4 Federal Price Regulation	27
IX	Payments and Accounting	27
	9.1 Billing	27
	9.2 Payment	28
	9.3 Billing Disputes	28
	9.4 Late Payment Charge	28

ARTICLE		PAGE
	9.5 Adjustments to Billings	29
	9.6 Cancellation in Event of Non-Payment	30
X	Term	31
	10.1 Term	31
	10.2 Termination by Seller	31
	10.3 Termination by Buyer	35
XI	Approval of Contract By State of Alaska and Effective Date	36
XII	Security	36
	12.1 Creation of Security Interest	36
	12.2 Alternative Security	38
XIII	Trade or Exchange of Crude	40
XIV	Default	40
	14.1 Default	40
	14.2 Disposition of Oil Upon Default, Cancellation or Termination	42
	14.3 Materiality of Breach	42
XV	Force Majeure	43
	15.1 Relief from Obligations	43
	15.2 Definition of "Force Majeure"	43
	15.3 Effect of Force Majeure	45
XVI	Notices	46
	16.1 Notices	46
	16.2 Change of Address	47
XVII	Waiver	47
XVIII	Records	47

ARTICLE		PAGE
	18.1 Preservation of Records	47
	18.2 Inspection of Records of Parties	48
	18.3 Financial Statements	49
XIX	Rules and Regulations; Sovereign Powers; Environmental Regulations and Standards	49
	19.1 Applicable Laws, Rules and Regulations	49
	19.2 Compliance with State Rules and Regulations .	49
	19.3 Compliance with Supplemental Environmental Standards	50
XX	Governing Law	50
XXI	Severability	50
XXII	Amendment	51
XXIII	Successors and Assigns	51
	23.1 General Prohibition of Assignment	51
	23.2 Limited Right of Assignment	51
XXIV	Equal Employment Opportunity	53
	24.1 Discrimination	53
	24.2 Advertisement of Equal Employment Opportunity	54
	24.3 Notices to Unions	54
	24.4 Inclusion of Equal Employment Opportunity Provisions in Contracts and Subcontracts	54
	24.5 Cooperation with Agencies of Seller	54
XXV	Local Hire and Training	56
	25.1 Local Hire	56
	25.2 Local Training	60
	25.3 Infrastructure Development	61
XXVI	Miscellaneous	61
	26.1 Exhibits	61
	26.2 Headings	61
	26.3 Gender	61

PAGE

ARTICLE

26.4 Counterparts 62
26.5 Additional Documents 62
26.6 Supplier-Purchaser Relationship 62
26.7 Reasonableness of Approvals 63

EXHIBITS

"A" ---Description of Leases

"B" ---Calculation of Monthly In Value Royalty Under the Leases and leases

"C" ---Form of Bond

"D" ---Supplemental Environmental Standards

AGREEMENT FOR THE SALE AND

PURCHASE OF STATE ROYALTY OIL

THIS AGREEMENT entered into as of the 22nd day of February, 1978, by and between THE STATE OF ALASKA, hereinafter called the "Seller," acting by and through its Commissioner of Natural Resources pursuant to Alaska Statute 38.05.183 and ALASKA PETROCHEMICAL COMPANY, an Alaskan corporation, hereinafter called the "Buyer."

W I T N E S S E T H :

WHEREAS, it is in the mutual best interests of Seller and Buyer that Buyer construct and operate a petrochemical facility in Alaska to process the oil sold hereunder, said facility to have the capacity to process approximately 30,000 barrels per day of crude oil into energy fuels for in-state distribution and sale; and

WHEREAS, Seller has the right under each of the Leases identified in Exhibit "A" to this Agreement to be delivered or paid by the Lessee thereunder a royalty of twelve and one-half percent (12-1/2%) in kind (amount) or value of the crude oil production removed or sold from the lands covered by each such Lease; and

WHEREAS, the Lessees of such aforesaid Leases and other parties have represented to Seller that crude oil can be recovered from such Leases in significant quantities and that such Lessees intend to market such crude oil; and

WHEREAS, Seller is presently receiving royalty payments based on more than 90,000 barrels of crude oil per day from the aforesaid Leases and anticipates the quantity of such royalty oil payments to increase for the next year; and

WHEREAS, Seller is authorized by Alaska Statute 38.05.183 to sell such royalty oil; and

WHEREAS, Seller desires to sell royalty oil to Buyer and Buyer desires to purchase royalty oil from Seller under the terms and upon the conditions hereinafter set forth;

NOW, THEREFORE, in consideration of the representations, covenants and conditions herein contained, Seller and Buyer hereby agree as follows:

ARTICLE I

DEFINITIONS

As used herein, the following terms shall have the following meanings:

1.1 "Affiliate" shall mean any person, firm, corporation or other entity affiliated with Buyer by means of a material direct or indirect ownership interest.

1.2 "Commissioner" means the Commissioner of Natural Resources of the State of Alaska.

1.3 "Date of First Delivery" means the date the first royalty oil sold hereunder passes the Point of Delivery.

1.4 "Day" means a period of twenty-four (24) consecutive hours beginning at 12:01 a.m., Alaska Standard Time.

1.5 "Effective Date" shall have the meaning defined in Article XI.

1.6 "Force Majeure" shall have the meaning defined in Article 15.2.

1.7 "Leases" or "Lease Contracts" means the oil and gas leases which are described in Exhibit "A" attached hereto and made a part hereof.

1.8 "Lessee" means any party owning a working interest in a Lease or Lease Contract.

1.9 "Month" means the period beginning at 12:01 a.m., Alaska Standard Time, on the first day of the calendar month and ending at the same time on the first day of the next succeeding calendar month.

1.10 "Oil" or "crude oil" shall have the same meaning as the word "oil" under the Prudhoe Bay Unit Agreement dated April 1, 1977, by and between the Seller and Lessees.

1.11 "Point of Delivery" shall have the meanings defined in Article III.

1.12 "Petrochemical Facility" shall have the meaning defined in Article 4.2.1.

1.13 "Total Project Costs" shall mean the aggregate of all sums and costs expended, incurred or contractually committed to be expended by Buyer, its Affiliates, direct and indirect beneficial shareholders, consultants, advisers and design, engineering and construction contractors in connection with responding to the requests

for proposal for the sale of royalty oil from the Leases; the preparation and execution of this Agreement; the performance of any and all obligations, transactions or events required by this Agreement; and the design, engineering and construction of the Petrochemical Facility or any portion thereof, all such costs to be measured from January 1, 1975. Total Project Costs shall also include (i) interest costs actually paid or accrued, and (ii) sums and costs expended, incurred or contractually committed to be expended by any city, borough or other governmental agency on any pollution control, sewage or water treatment, port, pipeline, terminal or other facilities, directly connected with or a part of the Petrochemical Facility, to the extent such facilities are utilized by the Petrochemical Facility. Any indirect or allocated costs shall be substantiated in writing to the satisfaction of the Commissioner.

ARTICLE II

QUANTITY PURCHASED AND SOLD

2.1 Sale of Prudhoe Bay Royalty Oil. Subject to the terms and conditions hereinafter provided, and subject to the prior obligations of Seller to deliver 5,000 barrels of crude oil per day under its contract with Golden Valley Electric Association, Inc. ("Golden Valley"), for the term and in the quantity now stated therein, Seller agrees to sell to Buyer, and Buyer agrees to buy from Seller, eighty-five percent (85%) of the total amount of Seller's royalty oil out of the crude oil production removed or sold from the Leases which the Seller has the right to take, and is available to the Seller for tak-

ing, in kind. Subject to the further provisions of Article 2.1, Seller reserves the right to use or dispose of the remaining fifteen percent (15%) in its discretion. After completion of the Petrochemical Facility, Seller's obligations to Golden Valley, if any, shall first be satisfied out of the fifteen percent (15%) portion of the oil from the Leases not being sold to Buyer hereunder. In addition to the crude oil deliverable under the other provisions of this Article 2.1, Buyer shall also possess the option to purchase an additional five percent (5%) of the total amount of Seller's royalty oil out of the Leases:

(a) in the event Seller enters into a contract with North Pole Refining Company ("NPR") granting NPR an option to purchase part or all of the fifteen percent (15%) portion of the oil out of the Leases not sold to Buyer under other provisions of this Article 2.1 and NPR does not exercise its option in full to purchase the oil on which it has an option, but Buyer's option to purchase shall extend only to the purchase of that quantity of oil from time to time not purchased by NPR; or

(b) in the event Seller does not enter into or have in effect a contract with NPR as recited in Article 2.1(a).

In the event it exercises its option under Article 2.1(a) or 2.1(b) above, Buyer agrees to give Seller an additional thirty (30) days notice of any nominations under this Article in addition to the time for notice specified in the Prudhoe Bay Unit Agreement. In the event under any agreement with NPR Seller obtains a right to purchase

from NPR any oil returned to the Trans Alaska Pipeline System by NPR, Seller shall assign all such rights to Buyer for the term of such NPR agreement.

Seller represents to Buyer that it has obtained sufficient advance written consents to termination and an agreement from Lessees (which to Seller's knowledge has been performed) to require similar consents from all subsequent purchasers agreeing to waive or terminate any supplier-purchaser relationship as to sufficient quantities of Seller's royalty crude oil out of the Leases to enable Seller to perform its delivery obligations under this Agreement.

2.2 Initiation of First Delivery. After the date Buyer has obtained the financing commitment referred to in Article 10.2(3)(d) and has furnished satisfactory evidence of same to Seller, Buyer shall have the right, subject to the further terms of this Article 2.2, to call for the initiation of delivery of crude oil under this Agreement by notifying Seller that Buyer seeks to initiate deliveries and stating the quantity desired, which such quantity shall be not less than one thousand (1,000) barrels per day. Initiation of deliveries, therefore, may occur prior to the date the Petrochemical Facility is completed and operational. Seller, within thirty (30) days after receipt of such notice from Buyer, shall deliver notice to all Lessees that it is exercising its right to take its royalty oil in kind and stating the quantity required to be delivered. In the event Seller shall obtain a modification of the Lease Contracts or Prudhoe Bay Unit Agreement to reduce the notice period required to less than six (6) months, the Date of First Delivery under this Agreement shall be reduced accordingly, but only upon sixty (60) days' prior written

notice of such time reduction to Buyer. Buyer agrees, in the event it calls for delivery of crude oil prior to the date the Petrochemical Facility is ready to process the crude oil, that it shall fully comply with its obligations under Article 26.6.

2.3 Certain Future Sales of Oil Taken in Kind by Seller. From and after the Effective Date, as to any royalty oil of Seller (other than royalty oil out of the Leases) taken in kind and proposed to be offered for sale, other use or disposition to third parties by Seller at a price or value which, when the reasonable costs of transportation of such royalty oil to the site of the Petrochemical Facility are added thereto, is less, on the date so offered, than the price stipulated in Article 8.1 plus the reasonable costs of transportation from the Point of Delivery to the site of the Petrochemical Facility, equitably adjusted to reflect quality and gravity differences between the crude oil offered to be sold and the crude oil from the Leases, Seller shall first offer to Buyer the opportunity to purchase ninety percent (90%) of the royalty oil proposed to be offered. Said oil shall be offered to Buyer at the same price, and on the same terms and conditions, as offered to third parties. The offer to Buyer shall remain open for sixty (60) days, after which time, if Buyer has not accepted the offer, Seller shall be free to sell the oil under the same terms and conditions to a third party. Seller may freely dispose of the ten percent (10%) portion of the royalty oil not sold to Buyer hereunder at such price and on such terms as Seller may desire. Notwithstanding the preceding provisions of this Article 2.3, Seller may freely sell any of its royalty oil otherwise subject

to this Article 2.3 free of the terms of this Article 2.3 so long as any such sales and deliveries of oil at a lower price, as defined above, cease and terminate on the date the Petrochemical Facility initiates processing of crude oil; further, the provisions of this Article 2.3 shall not apply to Seller's currently pending contract for the sale of oil out of the Leases to North Pole Refining Company nor to any renewal or renewals of the current contract of Seller with Tesoro Petroleum Company ("Tesoro") for a like quantity of oil as is now being delivered under Seller's contract with Tesoro. If Buyer purchases oil pursuant to the provisions of this Article 2.3, Buyer may reduce its purchases of royalty oil from the Leases by a like amount (and shall do so to the extent its aggregate purchases of all Seller's royalty crude oil under all provisions of this Agreement exceed 150,000 barrels per day, averaged monthly) during the period it is purchasing oil pursuant to this Article 2.3. Such reductions shall be effected in accordance with the restrictions of Article 2.5 and subject to Buyer's obligation to buy and receive such oil as it has previously nominated. Oil purchased pursuant to this Article 2.3 shall be deemed oil out of the Leases for the purposes of Article 14.1(ii) only.

2.4 Buyer Option in the Event Certain Quantities Not Delivered. Upon and after the inception of operation of the Petrochemical Facility, in the event at any time and from time to time Seller has not made available for delivery to Buyer for more than two (2) consecutive months average daily quantities (averaged monthly) of royalty crude oil from the Leases equal to or in excess of 145,000 barrels per day, upon written request by Buyer, Seller shall immediately exercise any option which it as lessor may then possess, as directed by Buyer, under any other lease or leases to receive its royalty crude oil in kind rather than in value in order that Buyer has the ability to receive from Seller 150,000 barrels of oil per day, with such prior notification to the lessees under such

other leases as may be required thereunder; provided, however, that the exercise of such option by Seller shall only apply to seventy percent (70%) of the available royalty oil to be taken in kind and only as to such quantity of royalty crude oil as may be necessary to assure Buyer of the availability of 150,000 barrels per day in the aggregate. To protect and insure Buyer's right to receive at least 150,000 barrels of crude oil per day hereunder, after the date of execution hereof and for the full term hereof, all contracts for the sale of any royalty crude oil of Seller taken in kind (except for Seller's currently pending contract for the sale of oil out of the Leases to North Pole Refining Company and except for any renewal or renewals of the current contract of Seller with Tesoro for a like quantity of oil as is now being delivered under Seller's contract with Tesoro) shall contain a provision that Buyer shall possess a paramount right to call for and receive such royalty oil in the event deliveries to Seller from the Leases and available for sale and delivery to Buyer fall below 145,000 barrels per day pursuant to the provisions of this Article 2.4. Notwithstanding any other provisions contained in this Article 2.4, Buyer's option hereunder shall extend only to seventy percent (70%) of the royalty oil production of any field, lease, or contract in which Seller has an interest. Seller agrees that any lease agreements and agreements for the sale of royalty crude oil taken in kind hereinafter entered into will include the advance written consent of the purchaser, exchange partner or other recipient of the crude oil to the termination of any supplier-purchaser relationship which may be deemed to exist

with respect to the State of Alaska royalty crude oil for purposes of any mandatory crude oil allocation program under applicable law or regulations of the Department of Energy or its successors then in effect upon the call therefor by Buyer under the provisions of this Article 2.4. In order to effectuate the purposes of this paragraph Seller shall furnish Buyer such information as Buyer reasonably requests from time to time concerning leases of which the State is Lessor and possesses the right to receive its royalty in kind. At such time as the average daily quantity of crude oil available to be delivered pursuant to the provisions of Articles 2.1 and 2.3 reaches or exceeds 150,000 barrels per day for more than two (2) consecutive months after such option has been exercised by Buyer, Seller shall have the right to terminate Seller's taking of royalty crude oil in kind under the other leases as described above in this Article 2.4, upon prior written notice which is thirty (30) days more than the period necessary to provide legal notice to Seller's lessees of Seller's return to taking its royalty in value rather than in kind, but on not less than ninety (90) days' written notice to Buyer. Thereafter, Buyer shall again be entitled to exercise its rights under this Article 2.4 should the aggregate average quantity of 145,000 barrels of crude oil per day available to be delivered under Articles 2.1 and 2.3 not be attained for more than two (2) consecutive months. If for any reason Buyer's election or elections to receive oil under this Article 2.4, along with the other obligations of Buyer to receive oil under this Agreement result in Seller being required to take from its Lessees or the lessees referred to in Articles 2.3 and 2.4

more than 150,000 barrels per day, Buyer will take all such oil from Seller and shall advise Seller so that Seller may give notice to its Lessees or lessees to reduce the quantities of oil it is taking in kind pursuant to Buyer's nominations to an aggregate of 150,000 barrels per day.

2.5 Increases or Decreases of Crude Oil. Notwithstanding any other provision of this Agreement to the contrary, after the Date of First Delivery and from time to time thereafter, Buyer shall have the right upon notice to Seller to require Seller to exercise its right under the Prudhoe Bay Unit Agreement (and under any other lease the oil from which is being sold to Buyer under Articles 2.3 and 2.4 if the terms of such lease so permit) to increase or decrease, by the terms of said Unit Agreement (or lease), the quantity of royalty oil to be delivered to Seller, and the quantity of royalty oil to be delivered to and purchased by Buyer under this Agreement shall be so adjusted; provided, however, that the provisions of this Article 2.5 shall not operate or be construed to require that Seller deliver and sell to Buyer the percentage portions of Seller's royalty oil out of the Leases or out of the leases referred to in Articles 2.3 and 2.4 which Seller has expressly reserved as not to be sold and deliverable hereunder, and further provided that Seller shall not be required to deliver more than 150,000 barrels per day hereunder as an average daily delivery during any calendar month. In addition to the time for notice specified in the Prudhoe Bay Unit Agreement (or any such other lease), Buyer agrees to give Seller an additional thirty (30) days' notice of any nominations under this paragraph. In order to provide maximum administrative efficiency, nominations

under this Article 2.5 shall be made not more than once every thirty (30) days.

2.6 Delivery of TAPS Fill by Seller. Upon initiation of deliveries pursuant to Article 2.2, Seller in addition to all other quantities of crude oil deliverable hereunder shall deliver to Buyer on or prior to the Date of First Delivery a sufficient quantity of crude oil for Buyer to fulfill its tariff obligations to supply Trans-Alaska Pipeline System pipeline fill and storage tank bottom requirements. Buyer shall pay for such quantity of oil on the date of termination pursuant to the provisions of Article IX, X or XIV hereof, at the price stipulated in Article VIII as if such oil had been delivered to Buyer at the Point of Delivery forty-five (45) days prior to the said date of termination. In the event that Buyer, prior to the completion of the Petrochemical Facility, suspends its purchase of oil from the Leases after having initiated deliveries and after Seller has delivered the pipeline fill and storage tank bottom requirements as provided by this Article 2.6, Buyer shall pay for such quantity of oil as if it had been delivered at the Point of Delivery on the date Buyer suspended its purchases. Thereafter Seller shall again be obligated to provide pipeline fill and storage tank bottom requirements upon Buyer's reinitiation of deliveries of oil out of the Leases as provided by other provisions of this Article II.

ARTICLE III

POINT OF DELIVERY AND PASSAGE OF TITLE

3.1 Point of Delivery. Delivery of the oil sold from

Seller to Buyer under Article 2.1 shall be made at the Seller's or Lessees' A.C.T. meter at the inlet inception point of the Trans-Alaska Pipeline System at Pump Station Number 1, Prudhoe Bay, Alaska. Delivery of any oil sold pursuant to the provisions of Articles 2.3 and 2.4 shall be at the same point of delivery that such oil is delivered to Seller by the lessee paying such oil as royalty oil in kind to Seller. Delivery under this Article 3.1 may be made at such other point or points of delivery as may be mutually agreed between Buyer and Seller. The Point or Points of Delivery set forth in this Article 3.1 shall hereinafter be referred to as the "Point of Delivery" or "Points of Delivery."

3.2 Passage of Title. Title to the oil to be sold hereunder shall pass from Seller to Buyer upon delivery.

3.3 Buyer's Responsibility. Buyer shall be responsible for the oil to be sold hereunder after passage of title hereunder. Buyer shall indemnify and hold Seller harmless from and against any and all claims, costs, damages, expenses or causes of action as a result of any loss, injury or damage incurred by any party as a result of any transaction or event which relates to the crude oil after title thereto has passed to Buyer. Buyer shall make all necessary arrangements for transporting the oil sold hereunder from the Point of Delivery.

ARTICLE IV

REPRESENTATIONS AND OBLIGATIONS OF BUYER

Buyer represents, warrants and agrees that:

4.1 Good Standing. Buyer is and at all times hereunder

will remain a corporation qualified to do business in, and in good standing with, the State of Alaska.

4.2 Construction of a Petrochemical Facility in the State of Alaska.

4.2.1 Construction Obligations. In consideration of the obligations assumed by each party herein, Buyer will proceed with reasonable diligence to design, construct, start up and thereafter initiate operation of a petrochemical manufacturing facility with fuels refining capacity in the State of Alaska. Such facility shall include facilities for the manufacture of energy fuels, aromatics, olefins and petrochemical derivatives of such basic feedstocks, and will include "offsite" facilities such as power supply, water supply, port facilities and administration buildings. Final process configuration and production rates of the various products listed above will be determined by (i) marketing considerations based on sales contracts for the products and (ii) process optimization of the overall facility design to produce the desired products in the most effective manner. Variations in process optimization will occur throughout the anticipated life of the facility. Such facilities shall be hereinafter referred to as the "Petrochemical Facility."

4.2.2 Siting of Petrochemical Facility. Buyer has chosen several preferred sites for the location of its Petrochemical Facility. Buyer shall notify the Commissioner no later than six (6) months after the Effective Date which site it has chosen (and the reasons for its choice of such site in reasonable detail), which

site shall be subject to the approval of the Commissioner within ninety (90) days after receipt of notice by Seller of Buyer's choice of site. In making his decision, the Commissioner shall consider, among other things, the desires of the people who live in the immediate surroundings of any proposed site. Failure of Buyer to receive written reply from the Commissioner within such ninety (90) day period shall be deemed an approval of the site selection; provided, however, that such approval shall in no manner diminish or alter Buyer's obligation to obtain all requisite state and federal permits, licenses and applications or to comply with other applicable laws or regulations. In the event the Commissioner disapproves a proposed site, Buyer shall resubmit with additional pertinent information its original proposed site or shall propose an alternate site to the Commissioner within ninety (90) days from the date Buyer receives notice of disapproval. Resubmissions or submissions of alternate sites shall continue in like manner until a site is approved by the Commissioner.

4.2.3 Progress Reports by Buyer. From the Effective Date and until the conditions stated in Articles 10.2(1) through 10.2(3) have been satisfied, on or before the twentieth (20th) day of each month, the Buyer shall furnish the Commissioner a written progress report as of the end of the preceding calendar month describing compliance with the requirements of Article 10.2, the engineering, design and construction activities of Buyer with respect to the Petrochemical Facility, progress in the marketing of the products therefrom, and the proposed financings and scheduled expenditures of the Buyer. After fulfillment of all the conditions stated

in Articles 10.2(1) through 10.2(3) and until all the conditions stated in Articles 10.2(4) through 10.2(9) have been satisfied, Buyer shall furnish like progress reports (also to be on the twentieth (20th) day of the month) each calendar quarter as of the end of the calendar month immediately preceding the month in which the report is made, beginning on the twentieth (20th) day of the third month next following the month during which the conditions under Articles 10.2(1) through 10.2(3) were fulfilled. Such reports, or portions thereof, shall be held confidential as requested by Buyer to the extent permitted by law.

4.3 Production of Energy Fuels for Intrastate Use. In order to provide fuels for distribution within the State of Alaska, Buyer shall design and construct the Petrochemical Facility to include a capacity to process 30,000 barrels of crude oil per day into energy fuels. If Buyer does not utilize the royalty oil sold and delivered hereunder, or traded or exchanged oil, in the Petrochemical Facility, then it shall utilize its best efforts to assure that at least 30,000 barrels per day of said royalty oil will be processed instate for production into energy fuels for intrastate distribution and sale, unless such processing would be surplus to the then prevailing intrastate domestic and industrial needs.

4.4 Establishment of Charitable Foundation. Buyer covenants and agrees to establish the Alaska Endowment Trust, the purpose of such trust being to further the social, educational, cultural and environmental conditions in the State of Alaska. The

Alaska Endowment Trust shall be established under the terms of a trust instrument proposed by Buyer and approved by the Governor of Alaska and Alaska Legislature; the trust corpus shall be administered by a Board of Trustees unaffiliated with Buyer. Trustees shall be appointed by the Governor of Alaska and confirmed by the Alaska Legislature. The corpus of the Alaska Endowment Trust shall be created from contributions by Buyer of amounts equal to five percent (5%) of the net after-tax profits, as hereinafter defined, realized from the operation of the Petrochemical Facility and sale of fuels and petrochemical products produced from the Petrochemical Facility. Each such annual contribution shall be paid on or before July 1 of each year based upon the net after-tax profits of the immediately preceding calendar year, the first such year of measurement to commence on January 1 next following ten (10) years after the Petrochemical Facility is completed, as measured by the delivery of the certificate of completion and operability by the prime contractor of Buyer in charge of construction of the Petrochemical Facility or sixteen (16) years after the Effective Date, whichever is earlier. "Net after-tax profits" shall mean the net income of Buyer prior to deduction or accrual of amounts payable under this Article 4.4 and shall be determined in accordance with generally accepted accounting principles applied on a consistent basis after deduction for all taxes which would have been provided for in the financial statements of Buyer for the year but for the payment of the amounts payable under this Article 4.4. Since the parties

have assumed that payments under this Article 4.4 will be deductible as an expense for purposes of any tax imposed on the income of Buyer, in the event any taxing authority does not permit such deduction, the amount payable hereunder shall be adjusted to reflect such non-deductibility. Charges made by or to any Affiliate shall be reasonable and shall not exceed those charges which would have been made in arm's length bargaining with an unaffiliated party in light of all the circumstances of the transaction, including the length of term of any contracts, financing terms and any other direct and indirect benefits offered or received. All sales between Buyer and any Affiliate shall be at a fair market price or value for such goods or services in light of all the circumstances, including the length of term of any contractual relationship, financing terms and any other direct or indirect benefits offered or received.

ARTICLE V

REPRESENTATIONS AND OBLIGATIONS OF SELLER

Seller represents, warrants and agrees that:

5.1 Seller's Royalty Oil. Pursuant to the Leases and the leases presently in effect and referred to in Article 2.4, Seller has the right to take its royalty in kind (amount), which royalty oil it represents is at least twelve and one-half percent (12-1/2%) of any crude oil production removed or sold from the Leases, unless otherwise described in Exhibit "A".

5.2 Title. Seller hereby warrants good and marketable title to the oil sold by it hereunder and its right to sell the same,

and warrants that all such oil is owned by Seller free from all liens, encumbrances and adverse claims.

5.3 Storage of Oil. Under Paragraph 13 of the Lease Contracts, Seller may be entitled, under certain conditions, to storage of Seller's royalty oil from Lessees free of charge. Seller hereby licenses to Buyer its storage rights, if any, under the Leases (and under any other leases the oil from which is being sold to Buyer pursuant to Articles 2.3 and 2.4) effective upon the Date of First Delivery, to the fullest degree permissible under the Lease Contracts and to an extent proportionate to the proportion of Seller's royalty oil being delivered hereunder. Seller further agrees that it will aid and work with Buyer to resolve any uncertainties or ambiguities concerning Seller's right to storage under the Lease Contracts, including the institution and pursuit of litigation at Buyer's cost to clarify Seller's legal rights of storage under said Paragraph 13. Buyer and Seller agree that their mutual objective shall be to maximize the Seller's and Buyer's rights to receive storage of the oil from the Lessees. Notwithstanding anything stated herein, Seller does not warrant that it possesses any right or rights to storage under the Lease contracts or any other leases. Buyer agrees that any failure to obtain storage hereunder from the Lessees shall not relieve Buyer of its obligations under Article 10.2. Buyer will indemnify Seller and hold it harmless against all claims, costs, loss or liabilities arising from Buyer's use of said storage facilities or rights.

5.4 Covenant to Aid in Obtaining Governmental Permits. In order to construct the Petrochemical Facility, Buyer must obtain numerous permits, licenses and authorizations from state, federal and other governmental authorities. Seller agrees to utilize its best efforts to support, lend aid and facilitate the grant or approval of Buyer's applications for such permits, licenses and authorizations; provided, however, that the obligations stated herein shall not require Seller to support, lend aid or facilitate the grant or approval of any permits, licenses and authorizations which do not comply with applicable rules, regulations or laws, and provided further that Seller's obligations herein shall not require Seller to waive, rescind, modify or otherwise alter (either in substance or procedure) any of Seller's regulatory responsibilities. Seller, acting through the Commissioner, within thirty (30) days after the Effective Date shall appoint a state official who shall act as Seller's coordinator for the purpose of facilitating the granting of permits by Seller and to act as a liaison officer for Buyer and Seller with the federal government. Such designation may be changed from time to time by the Commissioner.

5.5 Delivery of Information to Buyer. Seller shall deliver to Buyer without cost to Seller (unless any costs to Seller be indemnified by Buyer) within thirty (30) days after the Effective Date:

(i) the most recent report it possesses or can obtain from third parties concerning the volume of hydrocarbons originally in place and the portions or fractions thereof which will be recovered from the Prudhoe Bay unit reserves, accompanied by any related studies or data pertaining to such report;

(ii) the most recent anticipated production schedules of oil, solution gas, gas cap gas and condensate in its possession or obtainable from third parties out of the Prudhoe Bay unit by year; and

(iii) the most recent information, projections or estimates in its possession or obtainable from third parties of anticipated crude oil discovery and production in Alaska during the term of this Agreement.

During the term of this Agreement, as reasonably requested by Buyer in writing, Seller shall furnish updated information pertaining to Subparagraphs (i) through (iii) of this Article 5.5. Certain information and documents, including but not limited to well logs and related production data pertaining to the Leases and other leases referred to in Articles 2.3 and 2.4 may be required by law or regulation to be held confidential by Seller, its representatives and agents, and such documents shall not be required to be delivered hereunder. Seller understands and acknowledges the importance of reports taken from such data in securing financing for the Petrochemical Facility, and Seller agrees to use its best efforts to obtain and furnish to Buyer all such relevant data and reports as requested by Buyer. Seller agrees to retain, at Buyer's cost, independent consultants acceptable to Buyer to review confidential data, to prepare such updated reports and to state such opinions as may be reasonably requested by and furnished to Buyer to the extent permitted by applicable law and regulation. Seller's obligations under this section are for the purpose of aiding Buyer in obtaining up-to-date information, some or all of which may have been furnished to Seller by third parties; accordingly, Seller does not, by provid-

ing Buyer with the information specified in Subparagraphs (i) through (iii), warrant or represent the accuracy of such information, nor does Seller obligate itself to attempt in any way to bring about the conditions or projections contained in the information provided.

ARTICLE VI

QUALITY

6.1 Standard. The oil to be delivered by Seller to Buyer at the Point of Delivery hereunder shall be the same quality as the oil delivered by the working interest owners from the Leases and the leases. Except for the foregoing, Seller does not warrant, represent or guarantee, either expressly or impliedly the quality, merchantability, fitness for use, or suitability for any particular use or purposes, or otherwise of any oil to be delivered to Buyer under this Agreement. There are no warranties, representations or agreements concerning the quality of the oil which extend beyond the description of the oil in this Article VI.

ARTICLE VII

MEASUREMENTS AND TESTS

7.1 Testing Standards and Procedures. The quantity and quality of the crude oil sold and purchased from the Leases shall be determined at Lessees' A.C.T. meters at Pump Station No. 1, Prudhoe Bay, Alaska. The quantity and quality of the crude oil sold and purchased from the other leases shall be determined at the lessee's point of delivery. All measurements hereunder shall represent one hundred percent (100%) volume, consisting of United States barrels of forty-two (42) gallons, the quantity and gravity of which shall be adjusted to a temperature of sixty degrees (60°) Fahrenheit. Full deduction

shall be made for all basic sediment and water content according to the ASTM Standard Method then in effect. Unless agreed otherwise between Buyer and Seller or set forth herein, procedures for measuring and testing and for metering the crude oil shall be completed in accordance with standard oil field practices. Procedures for metering deliveries under the Leases shall be in accordance with accepted oil field practices in effect at Prudhoe Bay, Alaska. At the direction of Buyer, Seller shall direct the Lessees or lessees to test the accuracy of their measuring equipment if and to the extent that the provisions of the Prudhoe Bay Unit Agreement or any other agreement between Seller and Lessees or lessees permit Seller to make such request. Notice of the time and nature of each test of Lessees' or lessees' measuring equipment shall be given by Seller to Buyer sufficiently in advance to permit convenient arrangement for Buyer's representative to be present. Tests and adjustments shall be made in the presence of representatives of Buyer if present at the time scheduled for such test and adjustment. At Buyer's election and subject to obtaining the permission of any necessary third parties, Buyer may also install equipment to measure or gauge all oil received by Buyer hereunder at the Point of Delivery, and Buyer shall bear the entire acquisition, calibration, maintenance and operating cost of any such loading, measuring or testing equipment required by Buyer.

7.2 Delivery of Crude Oil Samples by Seller. Upon reasonable request by Buyer, Seller at its cost shall utilize its best efforts to aid Buyer in obtaining a representative sample of one barrel of crude oil taken at Valdez, Alaska, in order for Buyer

AGO 560133

to perform an assay to analyze the composition, gravity, sulphur content and other characteristics of such crude oil sample. If any sample of the oil is delivered to Buyer, there is no representation or warranty by Seller that any other oil delivered hereunder will conform to the sample, it being understood that Seller will deliver only such oil as shall be delivered to it by the Lessees or lessees under the Leases or leases. Seller shall provide Buyer copies of all other assays obtained or received by it during the term hereof.

ARTICLE VIII

PRICE

8.1 Price.

8.1.1 Price of Oil Delivered Out of the Leases. As to oil sold and delivered hereunder out of the Leases, the price to be paid by Buyer to Seller shall be equal to the sum the Seller would have received from the Lessees had Seller received its royalty in value instead of taking the quantity of royalty oil delivered hereunder as its royalty in kind (amount). Seller and Buyer recognize that the method and basis of computing the royalty due Seller from Lessees under the Leases is currently a matter of dispute and litigation among the Seller and its Lessees, said litigation being entitled State of Alaska, et. al. vs. Amerada Hess Corp. et al., (No. CA 77-847, Superior Court of the State of Alaska, First Judicial District at Juneau). Pending resolution of said dispute among Seller and Lessees, by judicial decision or settlement in the above-

referenced case, the in value royalty under the Leases, and therefore the price hereunder, shall be computed in accordance with Exhibit "B", attached hereto and by reference made a part hereof. After such time as said dispute shall be resolved among Seller and its Lessees, the parties hereto will be bound by the terms of such resolution, judicial or otherwise. Seller and Buyer expressly recognize that adjustment in prices previously paid may be necessary following said resolution and said adjustment shall be duly made, with interest, pursuant to the applicable provisions of Article IX. Any settlement agreement which agrees to the imposition of costs which are reimbursable by Buyer to Seller under Article 8.2, however, shall not be final and binding upon Buyer, unless Buyer has consented in advance to such settlement.

8.1.2 Price of Oil Sold Under Article 2.3. Oil sold pursuant to the provisions of Article 2.3 shall be the same lower price on the same terms and conditions as Seller is proposing to offer such oil.

8.1.3 Price of Oil Sold Under Article 2.4. The price of the oil sold pursuant to the provisions of Article 2.4 shall be the greater of (i) the best and highest price offered by a bona fide offeror for a like quality and quantity of the crude oil to be produced from such lease out of which oil is being delivered; or (ii) a price equal to the sum Seller would have received from its lessee or lessees had Seller received its royalty in value instead of taking the quantity of royalty oil delivered hereunder as its royalty in kind (amount).

8.2 Reimbursement of Certain Costs of Seller. In addition to the price stated in Article 8.1, Buyer shall also reimburse Seller for Seller's pro rata share of (i) any basic sediment and water removal costs if Seller is required to pay such costs as a result of Seller's election to take its royalty oil in kind; and (ii) any other direct costs reasonably incurred and paid by Seller which would not have been incurred by Seller had the Seller taken its royalty in value rather than in kind and if such costs under Article 8.2(i) and (ii) were not previously reflected in applicable computations of value for payments of royalty in value. Seller shall use its best efforts to minimize any such costs incurred by Seller by reason of Seller's taking royalty oil in kind; such best efforts shall include but not be limited to litigation in cooperation with and at the request of Buyer, at Buyer's cost, to the extent necessary to contest the imposition of unwarranted or improper charges; provided, however, that Seller shall in no event be required to advocate legal positions or adopt legal strategies which it, in its discretion, deems contrary to its own interests, in any such litigation. Seller at this date does not know of any potential costs to be incurred by it as a result of its taking in kind rather than invalue other than the costs stipulated in Article 8.2(i) above.

8.3 Minimum Taking in Value by Seller. In order to facilitate the establishment of prices under Article 8.1 Seller agrees at all times during the term of this Agreement to take and receive in value rather than in kind the minimum number of barrels per day required to obtain a report of the in-value price from each Lessee.

AGO 560136

8.4 Federal Price Regulation. In the event a maximum price is established by the federal government during the term of this Agreement which applies to the royalty oil and which is lower than the prices established under this Article VIII above, then Buyer shall pay the Seller that maximum price for royalty oil delivered to Buyer, but only during such period such maximum price is in effect.

ARTICLE IX

PAYMENTS AND ACCOUNTING

9.1 Billing. Seller shall furnish Buyer monthly, on or before the tenth (10th) business day of each month after the first full month of delivery of crude oil, a statement of account of all crude oil delivered through and measured at the Point of Delivery during the immediately preceding month according to the best information available to Seller, the price or prices applicable thereto according to the best information available to Seller, the basis for computation of the applicable price or prices in full detail and the total net amount due. Seller shall render its billings to Buyer based upon the values, receipts, costs and computations reported to Seller by the Lessees and the lessees referred to in Articles 2.3 and 2.4. Seller shall thereafter adjust its initial billings pursuant to Article 9.5. Buyer and its authorized agents shall be permitted access during reasonable business hours to Seller's books and records pertinent to this Agreement to determine the correctness of the billings of Seller to the extent not contrary to law.

AGO 560137

9.2 Payment. Buyer shall make payment on or before the twenty-fifth day of the calendar month in which such statement is rendered or fifteen (15) days after rendition of the invoice called for in Article 9.1, whichever is later, by direct wire transfer of federal reserve funds through the Federal Reserve Bank wire transfer system to the following address or such other address as Seller may designate upon seven (7) days' prior written notice:

Bank of America, NT & SA
San Francisco, California
Securities Department 3255
Credit to: State of Alaska
Investment Account

All other payments to be made under this Agreement shall be paid in the same manner. If payment is to be made on a Saturday, Sunday or legal holiday under the preceding provisions hereof, payment shall be made on the next following business day.

9.3 Billing Disputes. Should any portion of the account furnished to Buyer by Seller be disputed in good faith, Buyer and Seller agree to mutually arrive at a fair and equitable resolution of such dispute, if possible, and Buyer agrees to pay the amount so determined to be due to Seller within fifteen (15) days after such resolution. Buyer shall pay for such amounts as it does not in good faith dispute in accordance with the provisions of this Article IX.

9.4 Late Payment Charge. If Buyer fails to make timely payment to Seller of any amount due under this Agreement, including

any payment delayed by a bona fide dispute which is later determined to be validly owing, or if Buyer is required to pay and does pay any amount which is later determined not to be validly payable to Seller, interest shall accrue and be payable on said sum from the date when such payment was due or was paid, as the case may be, until the same is paid or repaid, at the lower of (i) a rate per annum equal to the prime rate then being charged by Chemical Bank of New York, New York, plus one and one-quarter percent (1-1/4%) per annum, or (ii) the maximum lawful rate of interest per annum which may be charged to Buyer under the laws of the State of Alaska.

9.5 Adjustments to Billings. Each month Seller shall adjust its statement of accounts to reflect the actual amounts delivered and the price or prices applicable thereto. Seller shall from time to time adjust its prior billings to reflect adjustments necessitated as a result of (i) a final judgment or settlement entered in certain pending litigation between Seller and the Lessees styled State of Alaska, et al. vs. Amerada Hess Corporation, et al., No. CA 77-847, in the Superior Court of the State of Alaska, First Judicial District at Juneau; (ii) adjustments necessitated as a result of the filing with the Seller by the Lessees or lessees of more current reports applicable to the billing period in question; (iii) actual adjustments necessitated as a result of changes to values, receipts, costs and computations previously reported by the Lessees or lessees and utilized by Seller as a basis for billing under Article 9.1, if such adjustments are based upon actual later severance tax or royalty

oil payments by or refunds to the Lessees or lessees; or (iv) adjustments required as a result of clerical or arithmetical errors in the billings of Lessees, of lessees, or of Seller; provided, however, that no adjustments, whether credits or debits, under Articles 9.5(ii) through 9.5(iv) shall be made by Seller or demanded by Buyer more than twelve (12) months after billing except as to matters which are the subject of (x) pending litigation by either party, (y) pending regulatory proceedings (or appeals thereof) whether or not Seller or Buyer is a party thereto, or (z) bona fide audits by Seller which audits have been terminated or completed by Seller within twelve (12) months after initiation of same.

Due to the potentially large sums of money involved, any adjustments to any billing under the provisions of this Article 9.5 by Seller made more than sixty (60) days after such billing was initially rendered shall be paid to or refunded by Buyer or Seller over the same period over which such adjustments accrued or thirty-six (36) months, whichever is longer, beginning with the first payment next following the date such adjustment has been determined; provided, however, no such payment extension permitted hereunder shall extend beyond the term stipulated in Article 10.1, and accordingly the full balance of any unpaid adjustments shall become due and payable on the termination date hereof.

9.6 Cancellation in Event of Non-Payment. Except for amounts disputed in good faith, should Buyer fail to make any payment due to Seller under this Agreement (i) within sixty (60) days

from the date said payment is due or (ii) within thirty (30) days from the date that Seller gives written notice of non-payment to Buyer in the manner provided in Article 16.1 hereinbelow (except that said notice shall be directed to the attention of the President of Buyer), whichever occurs earlier, this Agreement shall automatically be cancelled.

ARTICLE X

TERM

10.1 Term. Subject to the further provisions of Articles 10.2 and 10.3 this Agreement shall become effective on the Effective Date and except as extended by Article XV hereof shall continue and remain in force and effect for a period of twenty-seven (27) years from the Effective Date.

10.2 Termination by Seller. This Agreement shall terminate upon failure of Buyer to take each and every one of the following actions within the time specified for each, including any time extensions provided for in this Article 10.2:

(1) Within six (6) months after the Effective Date:

(a) Actually expend at least Two Million Dollars ($2,000,000.00) in Total Project Costs.

(b) Negotiate with interim lenders and obtain commitment to provide funds deemed necessary by Buyer for organizational costs and initial design costs of the Petrochemical Facility.

(c) Commence planning for optimization of design of the Petrochemical Facility.

(d) Notify Seller of Buyer's final selection of site location, such notification to be accompanied or preceded by site studies and recommendations based on preliminary engineering, including compression tests and cost estimates of infrastructure, offsite and marine facilities.

The Commissioner may extend the above six (6) month period as to Articles 10.2(1)(b), (c) and (d) thirty (30) days, but only in the event Buyer has, prior to such extension, fulfilled the requirements of Article 10.2(1)(a).

(2) Within twelve (12) months after the Effective Date:

(a) Actually expend at least Three Million Dollars ($3,000,000.00) in Total Project Costs.

(3) Within eighteen (18) months after the Effective Date:

(a) Expend or commit to expend or cause contractually bound third parties to expend or commit to expend at least Ten Million Dollars ($10,000,000.00) in Total Project Costs.

(b) Negotiate sale terms with prospective purchasers of products from the Petrochemical Facility; delineate product requirements, production ratios and quantities for the range of products to be produced from the Petrochemical Facility; and draft contracts for the sale of products from the Petrochemical Facility.

(c) Enter into contracts for the sale of at least seventy percent (70%) of the product output from the Petrochemical Facility.

(d) Obtain or cause contractually bound third parties to obtain written commitments to lend or invest at least One Billion Five Hundred Million ($1,500,000,000.00) in the aggregate for payment of Total Project Costs.

(e) Obtain a commitment or commitments for interim financing for the construction of the Petrochemical Facility.

(f) Complete and file an Environmental Impact Assessment on the Petrochemical Facility.

AGO 560142

(g) Complete and file all material state, local and federal permit applications.

(h) Complete plant design and optimization necessary to obtain a definitive project cost estimate ("definitive" meaning a cost estimate containing no more than fifteen percent (15%) variance in anticipated costs).

The Commissioner may extend the above eighteen (18) month period as to any one or more of the criteria or events stated in Articles 10.2(3)(a) through (h) six (6) months.

(4) Within twenty-four (24) months after the Effective Date:

(a) Expend or commit to expend or cause contractually bound third parties to expend or commit to expend at least One Hundred Million Dollars ($100,000,000.00) in Total Project Costs.

The Commissioner may extend the above twenty-four (24) month period as to the attainment of the criteria stated in Article 10:2(4)(a) six (6) months.

(5) Within thirty (30) months after the Effective Date:

(a) Execute definitive documents relating to the long-term loan of funds for the Petrochemical Facility.

(b) Commence construction of the Petrochemical Facility.

The Commissioner may extend the above thirty (30) month period as to one or more of the events or criteria stated in Articles 10.2(5)(a) and (b) above six (6) months.

(6) Within thirty-six (36) months after the Effective Date:

(a) Expend or commit to expend or cause contractually bound third parties to expend or commit to expend at least Six Hundred Million Dollars ($600,000,000.00) in Total Project Costs.

The Commissioner may extend the above thirty-six (36) month period as to the attainment of the criteria stated in Article 10.2(6)(a) six (6) months.

(7) Within forty-eight (48) months after the Effective Date:

(a) Expend or commit to expend or cause contractually bound third parties to expend or commit to expend at least One Billion Dollars ($1,000,000,000.00) in Total Project Costs.

The Commissioner may extend the above forty-eight (48) month period as to the attainment of the criteria stated in Article 10.2(7)(a) six (6) months.

(8) Within sixty (60) months after the Effective Date:

(a) Expend or commit to expend or cause contractually bound third parties to expend or commit to expend at least One Billion Two Hundred Million Dollars ($1,200,000,000.00) in Total Project Costs.

The Commissioner may extend the above sixty (60) month period as to the attainment of the criteria stated in Article 10.2(8)(a) nine (9) months.

(9) Within seventy-two (72) months after the Effective Date:

(a) Expend or commit to expend or cause contractually bound third parties to expend or commit to expend at least One Billion Five Hundred Million Dollars ($1,500,000,000.00) in Total Project Costs.

The Commissioner may extend the above seventy-two (72) month period as to the attainment of the criteria stated in Article 10.2(9)(a) twelve (12) months.

(10) In addition to the periods of time which the Commissioner may extend the periods for performance of the criteria stated in this Article 10.2, the Commissioner may further extend the time for performance of any of the criteria stated in Article 10.2(1) through 10.2(9) for that period of time necessary to permit the Commissioner and the Alaska State Legislature to consider an amendment or modification of this Agreement, particularly of the provisions contained in Article 10.2. Such time extension shall not, however, extend beyond a period of time in excess of ninety (90) consecutive days during which the Alaska State Legislature is in session, nor shall such time extension include a consecutive period of less than ninety (90) days during which the Alaska State Legislature is in session without the prior written consent of Buyer.

10.3 Termination by Buyer. In the event that Buyer after expending all reasonable efforts fails to obtain the necessary binding commitments from interim and permanent lenders for all the funds necessary to permit construction of the Petrochemical Facility under a loan or loans providing for repayment of such loans during the life of this Agreement or fails to obtain site approval from the Commissioner after submitting at least two sites to the Commissioner pursuant to Article 4.2.2, Buyer may thereupon elect to cease design and construction of the Petrochemical Facility and terminate this Agreement without liability to either party by giving Seller notice of termination; on the thirtieth (30th) day after the giving of such notice this Agreement shall terminate, and Buyer shall deliver to Seller all documents and data pertinent to the Petrochemical Facility (or

copies thereof) in its possession, including engineering and site selection information as may be reasonably requested by Seller.

ARTICLE XI

APPROVAL OF CONTRACT BY STATE OF ALASKA AND EFFECTIVE DATE

This Agreement shall take effect on the date on which this Agreement has been approved by concurrent resolution of a majority of each house of the Tenth Alaska State Legislature ("Effective Date").

ARTICLE XII

SECURITY

12.1 Creation of Security Interest. To secure payment of all amounts due Seller for oil sold hereunder, Seller retains and Buyer hereby grants a purchase money security interest in all of the oil delivered and to be delivered to Buyer hereunder and in all oil obtained by Buyer in exchange for oil purchased hereunder; the products made or processed from any such oil, including all substances, if any, commingled therewith, or added thereto; and in the proceeds of the sale of any such oil or products, including the accounts receivable of Buyer arising from its sales of oil or products manufactured therefrom. The security interest shall attach to the oil at the time and Point of Delivery but shall terminate as to oil or products therefrom sold to a bona fide purchaser of Buyer in the ordinary course of Buyer's business; provided, however, that the said security interest shall attach to the accounts receivable arising therefrom. Notwithstanding the provisions of this Article 12.1, Seller agrees that (i) the security interest in the oil shall not attach at the time and Point of Delivery but instead at the time the oil arrives and is delivered to Buyer at the outlet flange measuring device of the Valdez, Alaska terminal facility of the Trans-Alaska Pipeline System ("TAPS") as to any oil shipped under any tariff pertaining to the TAPS which contains a prohibition against carriage of oil on which a lien of a party other than the carrier thereof exists or which grants to any carrier the right to reject carriage of oil on which such a lien

AGO 560146

exists if Buyer has provided Seller a bond, letter of credit, marketable securities or other security, as described in Article 12.2 in an amount or of a value equivalent to the value of oil of Buyer in the TAPS on which no lien of Seller exists, unless Seller or Buyer has obtained and furnished for Buyer evidence that such prohibition or right of rejection has been effectively terminated or waived and is unenforceable; and (ii) no lien shall attach to any oil or products produced therefrom or accounts receivable created from the resale thereof as to which payments to Seller have been made for the account of Buyer if (a) such payments are not derived from the sale of property otherwise subject to the security interest of the Seller and (b) such payments are secured or are to be secured by such oil, such products or such accounts receivable. Seller agrees that any document filed to perfect Seller's purchase money security interest described in this Article 12.1 shall contain an exclusion to the effect set forth in the next preceding sentence. Buyer agrees that it shall not agree, or consent to, or permit the filing of, any lien or security interest in the oil other than the lien of a TAPS carrier nor shall it transfer title thereto prior to its arrival and delivery to Buyer at the outlet flange measuring device of the Valdez, Alaska terminal facility of the TAPS or prior to the attachment of Seller's security interest thereto upon such delivery. Buyer further agrees that it will not grant or consent to any security interest in the oil or other security in favor of any third party unless such third party agrees in writing prior thereto that such security interest is subordinate to the security interest of the Seller, except for the lien of a TAPS carrier or as provided otherwise in Article 12.1(ii). Buyer agrees to execute and file all documents necessary to perfect Seller's said security interest in the oil, proceeds from the oil and accounts receivable referred to above. "Proceeds of the sale" shall include proceeds derived from insurance or other payments resulting

from damage to or destruction of the oil or other property covered by the security interest. To secure such payment Buyer shall cause all policies of insurance on the oil or other property to which the security interest attaches to name the Seller as coinsured as its interests may appear.

12.2 Alternative Security. In lieu of the security interest provided in Article 12.1, Buyer may provide alternative security in the form of a bond attached hereto and made a part hereof as Exhibit "C", executed by the Buyer, as principal, and a corporate surety agreed to by the Commissioner and authorized to write such bonds in the State of Alaska, as surety for a sum which shall substantially reflect the amounts owed by Buyer to Seller plus an amount equal to the value of any oil delivered by Seller to Buyer and not yet billed pursuant to Article IX; provided that whenever Seller has reasonable grounds for asserting and does assert any claims against Buyer in excess of the penal sum of the bond of Buyer then in effect hereunder, Buyer after being so requested by Seller shall either increase the penal sum of such bond to an amount reasonably sufficient to cover the claim of Seller and all expenses which may be incurred by it in connection therewith or shall furnish other security satisfactory to Seller, such as a renewed security interest in the oil or a portion thereof sold hereunder, regardless of whether the Buyer does or does not recognize the validity of the Seller's claim (so long as reasonable grounds for asserting such claim exist). Buyer may at any time and from time to time deposit and maintain with the Commissioner at Buyer's expense in lieu of any such bond, either (i) an irrevocable letter or letters of credit addressed to the Commissioner issued by a state or national banking institution of the United States which is a member of the Federal Deposit Insurance

Corporation and has an aggregate capital and surplus of not less than $50,000,000, or (ii) marketable securities which are approved by the Commissioner, and which shall be transferable by the Commissioner or by delivery by stock power attached or other means, such letter or letters of credit to be in an aggregate amount, or such marketable securities to be of an aggregate then fair market value, of not less than the amount then required for Buyer's bond hereunder any such letter or letters of credit and marketable securities, together with any proceeds thereof, to be held by the Commissioner for the security and benefit of the Seller, and such letter or letters of credit or marketable securities along with instruments of transfer to be in form and substance approved by the Seller. The amount of said letter or letters of credit or marketable securities shall be subject to increase in the same manner that the face amount of the bond is subject to increase. If marketable securities are so furnished, other marketable securities which meet the requirements of this Subparagraph (a) may be substituted at any time and from time to time for any previously furnished marketable securities, and the marketable securities so furnished shall be increased if at any time the fair market value of the securities then held by the Commissioner is less than, or may be reduced if the fair market value thereof exceeds, the amount of the bond then required of Buyer hereunder. Buyer may, in lieu of any other security provide other security which in the opinion of the Commisioner is of equal value to the security above described.

ARTICLE XIII

TRADE OR EXCHANGE OF CRUDE

13.1 Subject to the provisions of Article 4.3 hereof and the further provisions of this Article 13.1, Buyer may trade or exchange any or all of the royalty crude oil for other crude oil or products. No trade or exchange by Buyer shall reduce the price to be paid to Seller under Article VIII hereof, and any such trade or exchange shall be without cost or expense to Seller. Buyer agrees not to trade or exchange royalty oil with another party unless that party agrees to give Buyer written permission to terminate the trade or exchange relationship upon the termination of this Agreement. Buyer shall require of any trade or exchange partner specific acknowledgment of Buyer's obligations under Article 26.6 and written permission from Buyer's trade or exchange partner to terminate the trade exchange arrangement upon termination of this Agreement. Buyer shall also require of its trade or exchange partner that it agrees to include provisions similar to this section in contracts for the sale, trade or exchange of the royalty oil and that all subsequent purchasers and trade or exchange partners will do likewise.

ARTICLE XIV

DEFAULT

14.1 Default. If

(i) either party shall fail to perform any of the covenants or obligations imposed upon it by this Agreement, except when such failure shall be excused under the force majeure provisions of Article XV, or

(ii) for any period of six (6) consecutive months, beginning one (1) year after the Petrochemical Facility has initiated processing of crude oil into petrochemicals, and subject to the provisions of Article XV, Buyer fails to purchase in the aggregate at least one-third (1/3) of the crude oil which could be purchased by Buyer out of the Leases and the leases referred to in Article 2.4 during any calendar month, or

(iii) Buyer becomes insolvent or commits any act constituting an act of bankruptcy, or

(iv) Buyer voluntarily files an action under the United States Bankruptcy Act, or

(v) Buyer fails to obtain the dismissal of any involuntary bankruptcy proceeding filed against it under the provisions of the United States Bankruptcy Act within thirty (30) days of the filing thereof,

then and in any such event, the other party may, at its option and without waiving any other remedy for breach hereof, indicate such party's election to cancel this Agreement by notice in writing specifying in detail wherein the default has occurred. Except for the instances stipulated in Articles 14.1(iii) through (v) above, and except for payment by Buyer to Seller, which shall be governed by Article 9.6, the party in default shall have thirty (30) days from the receipt of such notice to remedy such default and to pay the other party for all loss or damage incurred as a result of such default and indemnify such party against future claims or loss arising out of such default. Upon failure of the defaulting party to remedy its breach within the time stipulated above, this Agreement may be cancelled by the non-defaulting party by service of written notice thereof upon the defaulting party. Any cancellation under Article 9.6 or this Article 14.1 [except Article 14.1(ii)] shall not

prejudice the right of the party not in default to collect any amounts due it hereunder for any damage or loss suffered by it and shall not waive any other remedy to which the party not in default may be entitled for breach of this Agreement.

14.2 Disposition of Oil Upon Default, Cancellation or Termination. It is agreed that if Buyer shall for any reason fail to take the royalty oil hereunder as and when made available to the Buyer pursuant to Buyer's previous nominations, Buyer shall nevertheless pay Seller as though it had taken delivery of said royalty oil, unless Seller through an understanding with Lessees or the lessees referred to in Articles 2.3 and 2.4 is able to cancel delivery of the quantities called for in said nominations of Buyer. In the event of any cancellation or termination of this Agreement, whether under Articles 10.2 or 10.3, or because of default under this Article XIV or Article 9.6, Buyer shall have an obligation to continue to purchase Seller's royalty oil for up to seven (7) months following termination or cancellation of this Agreement in such quantities as Buyer has elected pursuant to the nomination procedure set forth in Article 2.5 in the six (6) months preceding termination of this Agreement, if Seller is required by the Lessees or the lessees under Articles 2.3 and 2.4 to accept delivery in kind for such period.

14.3 Materiality of Breach. No default or breach of, or failure of performance under, this Agreement shall be deemed to have occurred under this Agreement unless such default, breach or failure of performance is material or substantial under all the cir-

cumstances or involves the non-payment of any sum due under this Agreement which is not the subject of a bona fide dispute.

ARTICLE XV

FORCE MAJEURE

15.1 Relief from Obligations. Except for Buyer's and Seller's obligations to make payment under this Agreement and except for Buyer's obligation to take oil nominated by it, neither party hereto shall be liable for any failure to perform the terms of this Agreement when such failure is due in whole or substantial part to a "force majeure" as hereinafter defined; provided, however, that if an event constituting a force majeure shall prevent substantial performance of a party's obligations hereunder in light of all the circumstances, so as to prevent the party not claiming force majeure from obtaining the benefit of its bargain for a period in excess of four (4) years, said party not claiming force majeure shall have the option to terminate this Agreement. Said option must be exercised before the force majeure ceases to exist. The aforesaid proviso shall not permit the Seller to terminate in the event the force majeure in question is based upon Buyer's inability to obtain requisite state permits, authorizations, or licenses if Buyer has exercised the due diligence required by Article 15.2(ix). Other remedies otherwise available for default or breach in the event of termination after such four year period shall not thereby be affected.

15.2 Definition of "Force Majeure". The term "force majeure" as employed in this Agreement shall mean (1) acts of God;

(ii) strikes, lockouts or industrial disputes or disturbances; (iii) civil disturbances, arrests and restraint from rulers or people; (iv) interruptions by laws, orders, rules, regulations, acts or restraints of any government or governmental body having proper jurisdiction; (v) acts of the public enemy, wars, riots, blockades, insurrections, mobilization; (vi) acts of vandalism or sabotage; (vii) shortages, scarcity or inability to secure labor, fuel, power, equipment or materials (including inability to secure materials by reason of allocation promulgated by authorized governmental agencies), (viii) inability or failure of contractors or subcontractors to perform, (ix) inability to obtain requisite federal, state or other governmental permits, authorizations, or licenses provided the party claiming force majeure has exercised due diligence in attempting to obtain such permits, authorizations or licenses; (x) inability to ship materials because of unavailability of shipping, docking or wharfage not within the reasonable control of the party claiming the existence of a force majeure; (xi) epidemics, landslides, lightning, earthquakes, fire, explosion, floods, washouts, storms, other unusual adverse weather conditions; (xii) breakdowns of machinery, equipment or lines of pipe; (xiii) freezing of wells, pipe lines or other equipment; (xiv) shutdowns necessary for making repairs or alterations to pipe lines or plants, mechanical failure, or the necessity of testing wells, machinery or lines of pipe as may be required by governmental authority or as may be deemed necessary by the testing party for the safe operation thereof whether or not

of the kind herein enumerated; or (xv) any other event or condition otherwise not reasonably within the control of the party claiming force majeure, whether or not similar to the enumerations of (i) through (xiv).

15.3 Effect of Force Majeure. Upon the occurrence and discovery of an event constituting force majeure, the party claiming that the event is a force majeure shall notify the other party hereto of its claim of force majeure. The party claiming the existence of a force majeure shall, so far as reasonably possible, attempt to remedy such event with due diligence, and the obligations of the disabled party to perform under this Agreement, insofar as they are affected by such force majeure, shall be suspended from the time such force majeure occurs and for so long as the disability so caused should have continued had the party claiming the existence of the force majeure met its remedial obligations under this Article 15.3, and for no longer. The settlement of strikes or lockouts or industrial disputes or disturbances shall be entirely within the discretion of the party having the difficulty, and the above requirement that any force majeure shall be remedied with due diligence shall not require the settlement of strikes, lockouts or industrial disputes or disturbances by acceding to the demands of any opposing party therein when such course is inadvisable in the sole discretion of the disabled party.

ARTICLE XVI

NOTICES

16.1 Notices. Any notice, request, demand or statement provided for in this Agreement must be in writing, and may be given by depositing same in the mail, addressed to the party to be notified, postage prepaid, and registered or certified, with a return receipt requested, or by delivery of same in person to such other party. Notice deposited in the mail in the manner hereinabove described shall be effective upon the expiration of seven (7) days after it is so deposited. Notice given in any other manner shall be effective only if and when received by the addressee. For purposes of notice the addresses of the parties hereto shall be as follows:

If to Seller:

State of Alaska
Commissioner of Natural Resources
Pouch "M"
Juneau, Alaska 99811

and
Commissioner of Revenue
Pouch "S"
Juneau, Alaska 99811

and
Director, Division of Minerals
and Energy Management
323 Fourth Street
Anchorage, Alaska 99501

If to Buyer:

Alaska Petrochemical Company
601 W. 5th Avenue, #320
Anchorage, Alaska 99501

and
Alaska Petrochemical Company
P. O. Box 6554
Houston, Texas 77005

AGO 560156

16.2 Change of Address. Each party may change its address for notice by giving notice thereof in the manner hereinabove provided.

ARTICLE XVII

WAIVER

The failure of Seller or Buyer to insist upon strict performance of any provision hereof shall not constitute a waiver of, or estoppel against asserting, the right to require such performance in the future; a waiver or estoppel in any one instance shall not constitute a waiver or estoppel with respect to a later breach of a similar nature or otherwise; and a course of performance established by a party shall likewise not estop the other party from complaining of a later breach similar in nature.

ARTICLE XVIII

RECORDS

18.1 Preservation of Records. Buyer and Seller will preserve and maintain all books, accounts and records relating to or arising out of the performance of this Agreement, including but not limited to, the planning, construction and operation of the Petrochemical Facility and the purchase or resale of the royalty oil and its refined products for a period of four (4) years. Buyer will also maintain and preserve all similar books, accounts and records of which it has possession belonging to those third parties with whom it contracts for the performance of various parts of this Agreement. Neither Buyer nor Seller shall be required to retain

AGO 560157

any records for more than six (6) years unless retention of such records is specifically required by applicable law or regulation. Buyer shall either maintain its records within the State of Alaska or make such records available to Seller at Buyer's principal office in the State of Alaska within thirty (30) days after written request therefor by Seller.

18.2 Inspection of Records of Parties. Buyer and Seller will accord to each other and to their authorized agents, attorneys and auditors during reasonable business hours access to any and all property, records, books, documents and indexes thereto directly relating to the Buyer's or Seller's performance of this Agreement and which are under the control of the party from which access is desired so that the other party may inspect, photograph and make copies of such property, records, books, documents and indexes thereto. Notwithstanding the foregoing, (i) Seller shall not be required to disclose any information, data or records which are required to be held confidential by applicable state law or regulation, and (ii) Buyer shall not be required to disclose any information, data or records containing trade secrets which Buyer or its Affiliates, contractors or subcontractors by contract with unaffiliated third parties have agreed to hold confidential. Seller shall notify Buyer of all information obtained, recorded or copied from Buyer's records in order that Buyer may evaluate the advisability of seeking that such information be held confidential by Seller under applicable law or regulation or under the provisions of this Article.

AGO 560158

18.3 Financial Statements. So that Seller may be fully informed with regard to Buyer's financial capabilities on an on-going basis, Buyer will provide Seller with a financial statement at quarterly intervals during any periods which Buyer is receiving delivery of oil under this Agreement from Seller. In addition, Buyer will provide Seller with year-end financial statements audited by an independent certified public accounting firm. Preparation of the financial statements shall be at Buyer's cost. Said statements shall be communicated to Seller in the manner provided in Article 16.1.

ARTICLE XIX

RULES AND REGULATIONS; SOVEREIGN POWERS; ENVIRONMENTAL REGULATION AND STANDARDS

19.1 Applicable Laws, Rules and Regulations. This Agreement and the covenants contained herein shall not be interpreted as a limit on the exercise by the State of Alaska of any of its sovereign or regulatory powers, whether inherent or as may be set forth by constitution, statute or regulation, to protect the environment, fish and wildlife, or the health, safety, general welfare, lives or property of the people, of the State of Alaska. This Agreement is subject to all present and future valid laws, orders, rules and regulations of the United States, the State of Alaska, or any duly constituted agency thereof; provided, however, that this paragraph shall not be deemed a consent to any attempted alteration, amendment, termination or revocation of the contractual rights, obligations or duties of the parties hereto by the State of Alaska.

19.2 Compliance with State Rules and Regulation. Buyer

AGO 560159

shall comply with all valid and applicable laws and regulations with regard to maintaining the quality of the environment of the State of Alaska, the well-being of fish and wildlife of the State, and the health, safety and welfare of the citizens of the State of Alaska in the construction of the Petrochemical Facility, the operation and maintenance of the Petrochemical Facility during the term hereof, and with respect to Buyer's purchase, refining and resale of the oil sold hereunder.

19.3 Compliance with Supplemental Environmental Standards. Buyer agrees to comply with the environmental protection standards set forth in Exhibit "D", whether or not such standards are required presently or in the future by applicable governmental law or regulation; provided, however, that the Commissioner of the Department of Environmental Conservation shall possess the power and authority to waive or eliminate any such standards upon a showing of reasonable cause, and provided further that the standards set forth in Exhibit "D" are supplemental to, and not substitutive of, any present or future laws or regulations applicable to regulation of the environment of the State of Alaska.

ARTICLE XX

GOVERNING LAW

This Agreement shall be governed by and construed in accordance with the laws of the State of Alaska, excluding any conflicts-of-law rule or principle which might refer such construction to the laws of another state or country.

AGO 550160

ARTICLE XXI

SEVERABILITY

If any of the terms and conditions of this Agreement are held by any court or governmental authority of competent jurisdiction to contravene or to be invalid under the laws of any political body having jurisdiction over the subject matter hereof, such contravention or invalidity shall not invalidate the entire Agreement. Instead, this Agreement shall be construed as if it did not contain the particular provision or provisions held to be invalid, the rights and obligations of the parties hereto shall be construed and enforced accordingly if feasible, and this Agreement shall thereupon remain in full force and effect.

ARTICLE XXII

AMENDMENT

This Agreement may be supplemented, amended or modified only by a written instrument duly executed by both the parties hereto after proper prior authorization, including approval by the Alaska Royalty Oil & Gas Development Advisory Board and the Alaska State Legislature. Buyer agrees that in the event Article VIII of this Agreement is subsequently amended so as to materially reduce the consideration paid to the Seller, directly or indirectly, for the royalty oil, said amendment will only be effective after it has been approved by a direct vote of the people of the State of Alaska.

ARTICLE XXIII

SUCCESSORS AND ASSIGNS

23.1 General Prohibition of Assignment. Except as otherwise permitted under Article 23.2 no assignment of this Agreement shall be made by either party without first obtaining the written consent of the other party. The Commissioner may grant such consent on behalf of Seller.

23.2 Limited Right of Assignment. This Agreement shall bind and benefit the parties hereto and their respective successors and valid assigns, but no permitted conveyance or transfer of any interest of either party shall be valid until such other party has been furnished with written notice and a true copy of such conveyance or transfer and an assumption, if any, of this Agreement by such assignee. Either Buyer or Seller, or both, may assign its right, title and interest in, to and by virtue of this Agreement, including any and all extensions, renewals, amendments and supplements thereto to a trustee or trustees, individual or corporate, or to any lender or lenders, as security for bonds or other indebtedness, obligations or securities, without such trustee or trustees or lender or lenders assuming or becoming in any respect obligated to perform any of the obligations of the assignor, and if any such trustee or lender be a corporation, without its being required by the parties hereto to qualify to do business in the State of Alaska (but such trustee or lender shall be required to submit to the jurisdiction of the courts of the State of Alaska for matters relating to this Agreement), and no such assignment shall serve to relieve the assigning party of its obligations hereunder. Any assignment by Buyer pursuant to the next preceding sentence shall be subject to the prior written approval of the Commissioner of any such trustee or trustees or lender or lenders; provided, however, that on or after the date that all the conditions stated in Article 10.2(3) have been fulfilled, no such prior written approval shall be

required and such assignment to such trustee or trustees or lender or lenders may be freely made. In the event any such trustee or trustees, lender or lenders, or their assignee shall foreclose upon or otherwise assume ownership rights in and to this Agreement, thereupon such trustee or trustees or lender or lenders and their valid successor and assigns (i) shall assume such rights and benefits as well as obligations and liabilities only upon written notice given by it or them to Seller, (ii) shall have the right to receive from Seller, without assuming any obligations or liabilities under this Agreement, except as expressed below in the last sentence of this paragraph, any money or property owed by Seller to Buyer under this Agreement as of the date of such foreclosure, (iii) shall have the right to sell or assign their ownership rights to this Agreement to any person, without the consent of the Seller if such person assumes the obligations of Buyer under this Agreement, and (iv) following such further sale or assignment, shall be relieved of any obligations or liabilities provided for under this Agreement. Nothing contained within this Article 23.2 shall operate so as (1) to terminate or subordinate Seller's security interest in oil, products, proceeds of the sale, or (2) to cancel any obligation to provide security as set forth in Article 12.2, until money owed to Seller under this Agreement is paid.

ARTICLE XXIV

EQUAL EMPLOYMENT OPPORTUNITY

24.1 Discrimination. Buyer will not discriminate against

AGO 560163

any employee or applicant for employment because of race, color, religion, national origin, ancestry, age or sex. The Buyer will take affirmative action to insure that applicants are considered for employment, and that employees are treated during employment, without regard to their race, color, religion, national origin, ancestry, age or sex. Such action shall include, but not be limited to, the following: employment, upgrading, demotion, or transfer; recruitment or recruitment advertising; layoff or termination, rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Buyer agrees to post in conspicuous places, available to employees and applicants for employment, notices setting forth the provisions of this nondiscrimination clause.

24.2 Advertisement of Equal Employment Opportunity. The Buyer shall state, in all solicitations or advertisements for employees to work, that all qualified applicants will receive consideration for employment without regard to race, color, religion, national origin, ancestry, age or sex.

24.3 Notices to Unions. The Buyer will send to each labor union or representative of workers with which the Buyer has a collective bargaining agreement or other contract or understanding a notice advising the labor union or workers' representative of the Buyer's commitments under this Article and shall post copies of the notice in conspicuous places available to all employees and applicants for employment.

24.4 Inclusion of Equal Employment Opportunity Provisions

in Contracts and Subcontracts. The Buyer will include the provisions of Article 24.1 through 24.3 in its contracts pertaining to the construction and operation of the Petrochemical Facility and will require the inclusion of these provisions in every subcontract entered into by any of its contractors, so that such provisions will be binding upon each subcontractor of Buyer.

24.5 Cooperation with Agencies of Seller. The Buyer agrees that it will fully cooperate with the office or agency of the State of Alaska which seeks to deal with the problem of unlawful or invidious discrimination, and with all other State efforts to guarantee fair employment practices under this Agreement, and Buyer will comply promptly with all reasonable requests and directions from the State Commission for Human Rights or any of its officers or agents relating to prevention of discriminatory employment practice. Full cooperation as expressed above shall include, but not be limited to, being a witness in any proceeding involving questions of unlawful or invidious discrimination if such is deemed necessary by any official or agency of the State of Alaska; permitting employees of Buyer to be witnesses or complainants in any proceeding involving questions of unlawful or invidious discrimination, if such is deemed necessary by any official or agency of the State of Alaska; participating in meetings; submitting periodic reports on the equal employment aspects of present and future employment; assisting in inspection of the Petrochemical Facility site during and after the construction; and promptly complying with all

directives deemed essential by any office or agency of the State of Alaska to insure compliance with all federal and state laws, regulations and policies pertaining to the prevention of discriminatory employment practices.

ARTICLE XXI

LOCAL HIRE AND TRAINING

25.1 Local Hire.

(1) Buyer will comply with all applicable Alaska statutes and regulations in effect at the time this Agreement becomes effective as well as all amendments thereto and subsequent enactments providing for local or resident hire.

(2) In addition, and subject to compliance with other requirements of state or federal law or regulation, Buyer will give preference to hiring qualified and available residents over nonresidents for all work to be performed in the construction, operation and maintenance of the Petrochemical Facility. Buyer shall not discriminate against Alaska residents by differentiating between residents and nonresidents in payment of wages, salaries, fringe benefits and working conditions. Nothing shall prohibit the Buyer from hiring Alaska residents through private sources. However, if private sources are unable to supply qualified Alaska residents, Buyer shall then attempt to seek qualified Alaska residents through the Alaska Department of Labor prior to the employment of nonresidents. The Buyer shall allow said Department of Labor two days, excluding Saturday, Sunday and state holidays, to produce

qualified resident workers prior to the employment of nonresidents. If suitable resident workers are not provided within the specified time period, the Buyer may employ nonresidents possessing the qualifications necessary to perform the work. Notwithstanding the foregoing, the Buyer may hire nonresidents (i) on an emergency basis for the duration of any emergency, (ii) as casual or intermittent employees if their employment will not exceed thirty (30) working days, or (iii) as specially skilled employees when the Department of Labor agrees in advance that such specially skilled persons are unavailable within the State of Alaska.

(3) Buyer will use its best efforts to incorporate in any and all collective bargaining agreements into which it enters with labor unions covering work to be performed in the construction, operation and maintenance of the Petrochemical Facility and associated facilities and operations, a provision or provisions requiring the unions' dispatch procedures be established and operated in a manner which will assure that qualified Alaska residents will be employed to perform said work.

(4) Buyer will incorporate in any and all agreements into which it enters with contractors and subcontractors provisions requiring the employment of qualified Alaska residents, as set forth in Article 25.1(2), and utilization of the contractors' or subcontractors' best efforts to obtain agreements with labor unions, as specified in Article 25.1(3).

(5) Noncompliance with the preceding covenants of

this Article 25.1 or of Article XXIV shall be grounds for a complaint which an aggrieved resident or the State of Alaska, on its own motion, may file with the Department of Labor against the Buyer, but shall not be considered a default under Article XIV. Buyer hereby agrees to submit to the jurisdiction of the Department of Labor for purposes of determining whether noncompliance in fact occurred. Said Department shall hold a hearing at which the parties may present relevant evidence and cross-examine witnesses prior to such a determination. Adequate notice thereof shall be given to all parties concerned. Upon a determination that noncompliance occurred, the Buyer shall pay the aggrieved party a sum equal to the amount the resident would have received had he been employed by the Buyer, up to a maximum of one (1) year's salary. If such compliance is determined to have been willful, the Department may award an additional sum up to the amount of the original sum awarded.

(6) For purposes of this Article

(a) "resident" means a person who

(i) except for brief intervals, military service, attendance at an educational or training institution, or for absences for good cause, is physically present in the state for a period of one year immediately before the time his status is determined;

(ii) maintains a place of residence in the state;

(iii) has established residency in the state;

(iv) has not, within the period of required residency, claimed residency in another state; and

(v) shows by all attending circumstances that his intent is to make Alaska his permanent residence;

provided, however, that in the event a final judgment is rendered by a court of competent jurisdiction in the State of Alaska that the one year period stated in Alaska Statutes Section 38.40.090 is unconstitutional because of the length of time, the one year period stated in this subparagraph shall be reduced to such period as is constitutionally acceptable;

(b) "qualified" means capable, through education, training or experience, of performing the duties and satisfying the usual terms and conditions of the employment, if those duties, terms and conditions meet the reasonable standards of the industry as required of other employees performing the same type of work in the industry;

(c) "willful noncompliance" means intentionally, knowingly, or purposely, without justifiable excuse, not giving preference to qualified Alaska residents in employment covered by this section; and

(d) "noncompliance" means not giving preference to qualified Alaska residents in employment covered by this Article 25.1.

(7) The performance of this Article 25.1 shall not be interpreted to require any action which constitutes the violation of any federal or state law or regulation, particularly those relating to discrimination in hiring.

25.2 Local Training. Buyer, in order to effectuate the purposes of Article XXIV and Article 25.1, and in order to insure the maximum practicable employment of Alaska residents in the operation and maintenance of the Petrochemical Facility, shall initiate training programs to provide skilled local personnel and adequately trained residents to apply for permanent employment in the operation and maintenance of the Petrochemical Facility. Buyer shall establish and furnish to Seller its employment requirements for the operation and maintenance of the Petrochemical Facility, including the approximate numbers of employees and identification of the types of skills needed, in sufficient time (but not more than one year) for Seller and Buyer to design and conduct its training programs in the skills required. In pursuing such programs, Buyer intends to and shall seek the support and financial aid of other groups and agencies, to wit: the federal government, Seller, municipal and local authorities, unions, and certain native Alaskan corporations. Seller will provide Buyer with reasonable assistance in the design and administration of the training program. Due to the difficulty of establishing objective criteria to insure that adequate effort has been expended by Buyer and because Buyer expects Seller to join with it in establishing such training programs and obtaining funds therefor from a variety of governmental sources, including Seller itself, Buyer's obligations under this program shall be deemed fulfilled in the event that Buyer has expended $500,000 on such training programs or, in the alternative, that an aggregate of $1,000,000 has

been expended from all sources (including all federal, private and state funds) on such training programs on or prior to ten (10) years from the Effective Date.

25.3 Infrastructure Development. Buyer agrees to use its best efforts to coordinate construction of the Petrochemical Facility with local municipal and borough authorities in order that development of supporting residential, service and other aspects of infrastructure may be coordinated. To that end, Buyer shall seek to arrive at mutually satisfactory solutions with municipal and borough governments to the perceived heavy demand on the physical plant and services of neighboring communities as a result of the construction and operation of the Petrochemical Facility.

ARTICLE XXVI

MISCELLANEOUS

26.1 Exhibits. Exhibits "A" through "D", which are attached to this Agreement, are by this reference incorporated into and made a part of this Agreement.

26.2 Headings. The headings of this Agreement are inserted for convenience and identification only and are not intended to describe, interpret, define or limit the scope, extent or intent of this Agreement or any provision hereof.

26.3 Gender. Whenever the context requires, the gender of all words used in this Agreement shall include the masculine, feminine and neuter, and the number of all words shall include the singular and the plural.

AGO 560171

26.4 Counterparts. This Agreement may be executed in any number of counterparts with the same effect as if Seller and Buyer had signed one document. All counterparts shall be construed together and shall constitute one and the same instrument.

26.5 Additional Documents. In connection with this Agreement, as well as all transactions contemplated by this Agreement, Seller and Buyer agree to execute and deliver such additional documents and instruments and to perform such additional acts as may be necessary or appropriate to effectuate, carry out and perform all the terms, provisions and conditions of this Agreement and all such transactions.

26.6 Supplier-Purchaser Relationship. Buyer and Seller each agree to take all action reasonably necessary or appropriate to effect the transactions contemplated by this Agreement and each party's performance of its obligations hereunder. In the event that this Agreement is canceled or terminated by any party pursuant to the terms hereof, Seller and Buyer hereby agree to waive any rights which either party may have to a continuation of any supplier-purchaser relationship that may have been established with respect to the State of Alaska royalty crude oil for purposes of any federal mandatory crude oil allocation program. Specifically, the Buyer expressly states and the Seller agrees that the consent given in the immediately preceding sentence is such a consent to the termination of any supplier-purchaser relationship between the Seller and the Buyer which may be deemed to exist

AGO 560172

under the Federal Mandatory Petroleum Allocation Regulations (10 C.F.R., Part 211) as is provided in 10 C.F.R. 211.63(d)(1)(i) of such Regulations. Seller and Buyer also agree that any subsequent contracts for the sale, exchange or other disposition of the State of Alaska royalty crude oil that may be entered into by the Buyer or Seller herein will include the advance written consent of the purchaser, exchange partner or other recipient of the crude oil to the termination of any supplier-purchaser relationship which may be deemed to exist with respect to the State of Alaska royalty crude oil for purposes of any mandatory crude oil allocation program upon the expiration, cancellation or termination of the underlying contractual agreement for the sale, exchange or other disposition of the crude oil or in the event that the agreement between the Seller and the Buyer for the sale and purchase of the crude oil is terminated for any reason, including termination for default as stated in Articles IX and XIV or because Buyer fails to meet its obligations under Article 10.2. Buyer also agrees to include in any contracts for the sale, exchange or other disposition of the State of Alaska royalty crude oil an agreement by the purchaser, exchange partner or other recipient of the crude oil to include identical waiver provisions in all subsequent sales, exchanges or other disposition of the crude oil by that purchaser, exchange partner or other recipient and by any subsequent purchasers, exchange partners or other recipients.

26.7 Reasonableness of Approvals. Buyer and Seller agree

that as to any approvals or consents required of either of them under this Agreement, except for extensions of time periods under Article 10.2, such approvals or consents shall not be unreasonably withheld.

IN WITNESS WHEREOF, the Seller has caused this Agreement to be executed by its Commissioner of Natural Resources and the Buyer has caused this Agreement to be executed by its President, thereunto duly authorized by its Board of Directors in accordance with the certified seal, duly attested, to be affixed hereto, as of the day and year first above written.

THE STATE OF ALASKA

ATTEST:

Frederick H. Boness

By: Robert E. LeResche
Commissioner, Department of Natural Resources
"SELLER"

APPROVED AS TO FORM:

Attorney General

ALASKA PETROCHEMICAL COMPANY

ATTEST:

Willard Hanzlik

By: O. Charles Haning
President
"BUYER"

I, Willard Hanzlik, certify that I am the Secretary of the corporation named as Buyer in the above contract, that

O. Charles Honig was then President of said corporation; that said Agreement was duly signed for and in behalf of said corporation by authority of its governing body, and is within the scope of its corporate powers.

Willard Hunsaker
Secretary

(CORPORATE SEAL)

THE STATE OF ALASKA)
) ss.
First JUDICIAL DISTRICT)

THIS IS TO CERTIFY that on this 22nd day of February, 1978, before me, the undersigned, a Notary Public in and for the State of Alaska, duly commissioned and sworn as such, personally appeared Robert E. Lekosche, to me known to be the Commissioner of Natural Resources for the STATE OF ALASKA, and known to me to be the person who executed the within instrument on behalf of the STATE OF ALASKA, and acknowledged to me that the same was signed as a free act and deed of the STATE OF ALASKA for the purposes and uses therein stated.

WITNESS my hand and notarial seal the day and year last above written.

Lennie Boston
NOTARY PUBLIC in and ~~for~~ Alaska.
My commission expires: Nov. 2, 1980

THE STATE OF ALASKA)
) ss.
First JUDICIAL DISTRICT)

THIS IS TO CERTIFY that on the 2nd day of February, 1978, before me, the undersigned, a Notary Public in and for the State of Alaska, duly commissioned and sworn as such, personally appeared the President of ALASKA PETROCHEMICAL COMPANY, an Alaska corporation, and known to me to be the person who executed the within instrument on behalf of the corporation herein named, and acknowledged to me that the same was signed as a free act and deed of said corporation for the uses and purposes therein stated and pursuant to its Bylaws or a resolution of its Board of Directors.

WITNESS my hand and notarial seal the day and year last above written.

Lennie Boston
NOTARY PUBLIC in and for Alaska.
My commission expires: Nov. 2, 1980

AGO 560176

CERTIFICATE

I, O. Charles Honig, President and a member of the Board of Directors of ALASKA PETROCHEMICAL COMPANY, an Alaska corporation, do hereby certify that the following is a true and correct copy of a resolution adopted by the Board of Directors of said ALASKA PETROCHEMICAL COMPANY at a special meeting duly called and held at Juneau, Alaska, on February 22, 1978:

> BE IT RESOLVED by the Board of Directors of Alaska Petrochemical Company that the Agreement for the Sale and Purchase of State Royalty Oil between Alaska Petrochemical Company and the Commissioner of Natural Resources of the State of Alaska presented to the Board at a special meeting duly called and held in Juneau, Alaska, on February 22, 1978, be and is hereby approved;
>
> BE IT FURTHER RESOLVED that the officers of the corporation be and hereby are authorized and directed to execute said Agreement for the Sale and Purchase of State Royalty Oil in the name of Alaska Petrochemical Company, and all further agreements and instruments that may be necessary or desirable to implement the purposes of that agreement.

O. Charles Honig
President

SUBSCRIBED and SWORN to before me this 22nd day of February, 1978.

Lonnie Boston
NOTARY PUBLIC in and for Alaska.
My commission expires: Nov. 2, 1980

AGO 560177

EXHIBIT "A"

Attached to and Made a Part of the Agreement for the Sale and Purchase of State Royalty Oil dated February 22, 1978, between ALASKA PETROCHEMICAL COMPANY, an Alaska corporation "Buyer", and the COMMISSIONER OF NATURAL RESOURCES OF THE STATE OF ALASKA, acting pursuant to Alaska Statute 38.05.183, "Seller", With Respect to Certain Royalty Oil Owned and Taken In-Kind by Seller Under the Leases Described Herein Covering Lands in the State of Alaska.

Tract No.	Description (Umiat Meridian, Alaska)	No. of Acres	ADL Serial No.	Basic Royalty	Lessee of Record	O.R.R. Interest	Working Interest Ownership
1	T12N-R11E, Secs. 9, 10	1,280	47445	1/8	Mobil and Chevron		Mobil—50% Chevron—50%
2	T12N-R11E, Secs. 11, 12	1,280	28235	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
3	T12N-R12E, Sec. 7	580	28254	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
4	T12N-R15E, Sec. 23, 24	1,280	34625	1/8	Sohio Petroleum Co.	*	Sohio—100%
5	T12N-R15E, Secs. 21, 22	1,280	34626	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
6	T12N-R15E, Secs. 19, 20	1,225	34627	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
7	T12N-R14E, Secs. 23, 24	1,280	34624	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
8	T12N-R14E, Sec. 22	640	28297	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
9	T12N-R13E, Sec. 19	585	47469	1/8	Mobil and Phillips		Mobil—50% Phillips—50%
10	T12N-R12E, Secs. 23, 24	1,280	47448	1/8	Mobil and Phillips		Mobil—66⅔% Phillips—33⅓%
11	T12N-R12E, Secs. 21, 22	1,280	28256	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
12	T12N-R12E, Secs. 17, 18, 19, 20	2,448	28255	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
13	T12N-R11E, Secs. 13, 14, 23, 24	2,560	28237	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
14	T12N-R11E, Secs. 15, 16, 21, 22	2,560	47447	1/8	Mobil and Chevron		Mobil—50% Chevron—50%
15	T12N-R11E, Secs. 17, 18, 19, 20	2,448	47446	1/8	Mobil and Chevron		Mobil—50% Chevron—50%
16	T12N-R10E, Secs. 13, 24	1,280	25637	1/8	A.R.Co., BP Alaska, Sohio Petroleum Co.		A.R.Co.—50% BP Alaska—37½% Sohio—12½%
17	T12N-R11E, Secs. 29, 30, 32	1,868	47449	1/8	Mobil and Chevron		Mobil—50% Chevron—50%
18	T12N-R11E, Secs. 27, 28, 33, 34	2,560	28239	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
19	T12N-R11E, Secs. 25, 26, 35, 36	2,560	28238	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
20	T12N-R12E, Secs. 29, 30, 31, 32	2,459	28259	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
21	T12N-R12E, Secs. 27, 28, 33, 34	2,560	28258	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
22	T12N-R12E, Secs. 25, 35, N/2 and SE/4 Sec. 26	2,400	28257	1/8	Mobil and Phillips		Mobil—50% Phillips—50%

*See comment on page A-5.

Tract No.	Description	No. of Acres	ADL Serial No.	Basic Royalty	Lessee of Record	O.R.R. Interest	Working Interest Ownership
	(Umiat Meridian, Alaska)						
22A	T12N-R12E, SW/4 Sec. 26	160	28257	1/8	Mobil, Phillips, Chevron		Mobil—33⅓% Phillips—33⅓% Chevron—33⅓%
23	T12N-R13E, Secs. 29, 30, 31, 32	2,459	28279	1/8	Sohio Petroleum Co.	*	Sohio—100%
24	T12N-R13E, Secs. 27, 28, 33, 34	2,560	28278	1/8	Sohio Petroleum Co.	*	Sohio—100%
25	T12N-R13E, Secs. 26, 35, 36	1,920	28277	1/8	Sohio Petroleum Co.	*	Sohio—100%
26	T12N-R14E, Secs. 29, 31, 32	1,871	28299	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
27	T12N-R14E, Secs. 27, 28, 33, 34	2,560	28300	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
28	T12N-R14E, Secs. 25, 26, 35, 36	2,560	28301	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
29	T12N-R15E, Secs. 29, 30, 31, 32	2,459	34628	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
30	T12N-R15E, Secs. 27, 28, 33, 34	2,560	34629	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
31	T12N-R15E, Secs. 25, 26, 35, 36	2,560	34630	1/8	Sohio Petroleum Co.	*	Sohio—100%
32	T12N-R16E, Secs. 29, 30, 31, 32	2,459	34635	1/8	Sohio Petroleum Co.	*	Sohio—100%
33	T12N-R16E, Secs. 27, 28, 33, 34	2,560	34634	1/8	Sohio Petroleum Co.	*	Sohio—100%
34	T12N-R16E, Secs. 25, 26, 35, 36	2,560	34633	1/8	Sohio Petroleum Co.	*	Sohio—100%
35	T11N-R16E, Secs. 1, 2, 11, 12	2,560	34636	1/8	Sohio Petroleum Co.	*	Sohio—100%
36	T11N-R16E, Secs. 3, 4, 9, 10	2,560	28337	1/8	Sohio Petroleum Co.	*	Sohio—100%
37	T11N-R16E, Secs. 5, 6, 7, 8	2,469	28338	1/8	Sohio Petroleum Co.	*	Sohio—100%
38	T11N-R15E, Secs. 1, 2, 11, 12	2,560	28320	1/8	Sohio Petroleum Co.	*	Sohio—100%
39	T11N-R15E, Secs. 3, 4, 9, 10	2,560	34631	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
40	T11N-R15E, Secs. 5, 6, 7, 8	2,469	34632	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
41	T11N-R14E, Secs. 1, 2, 11, 12	2,560	28302	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
**42	T11N-R14E, Secs. 3, 4, 9, 10	2,560	28303	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
43	T11N-R14E, Secs. 5, 6, 7, 8	2,469	28304	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
44	T11N-R13E, Secs. 1, 2, 11, 12	2,560	28290	1/8	Sohio Petroleum Co.	*	Sohio—100%
45	T11N-R13E, Secs. 3, 4, 9, 10	2,560	28291	1/8	Sohio Petroleum Co.	*	Sohio—100%
46	T11N-R13E, Secs. 5, 6, 7, 8	2,469	28282	1/8	Sohio Petroleum Co.	*	Sohio—100%
47	T11N-R12E, Secs. 1, 2, 11, 12	2,560	28260	1/8	Sohio Petroleum Co.	*	Sohio—100%
48	T11N-R12E, Secs. 3, 4, 9, 10	2,560	28261	1/8	Mobil and Phillips		Mobil—50% Phillips—50%
49	T11N-R12E, Secs. 5, 6, 7, 8	2,469	47450	1/8	Mobil, Phillips, Chevron		Mobil—33⅓% Phillips—33⅓% Chevron—33⅓%
50	T11N-R11E, Secs. 1, 2, 11, 12	2,560	28240	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
51	T11N-R11E, Secs. 4, 9, 10, N/2 and SW/4 Sec. 3	2,400	28241	1/8	Mobil and Phillips		Mobil—50% Phillips—50%
51A	T11N-R11E, SE/4 Sec. 3	160	28241	1/8	Mobil, Phillips, Chevron		Mobil—33⅓% Phillips—33⅓% Chevron—33⅓%

*See comment on page A-5.

**ADL 28303 has been certified as a discovery royalty lease. Basic royalty is 12-1/2% of production, but may be reduced to 5% for a period not to exceed ten (10) years.

Tract No.	Description	No. of Acres	ADL Serial No.	Basic Royalty	Lessee of Record	O.R.R. Interest	Working Interest Ownership
	(Umiat Meridian, Alaska)						
52	T11N-R11E, Sec. 15	640	28244	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
53	T11N-R11E, Secs. 13, 14, 24	1,920	28245	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
54	T11N-R12E, Secs. 17, 18, 19	1,840	28262	1/8	Chevron		Chevron—100%
54A	T11N-R12E, Sec. 20	640	28262	1/8	Chevron, Mobil, Phillips		Chevron—33⅓% Mobil—33⅓% Phillips—33⅓%
55	T11N-R12E, Secs. 15, 16	1,280	28263	1/8	Mobil and Phillips		Mobil—50% Phillips—50%
55A	T11N-R12E, Secs. 21, 22	1,280	28263	1/8	Mobil, Phillips, Chevron		Mobil—33⅓% Phillips—33⅓% Chevron—33⅓%
56	T11N-R12E, Secs. 13, 14, 23, 24	2,560	47431	1/8	Mobil, Phillips, Chevron		Mobil—33⅓% Phillips—33⅓% Chevron—33⅓%
57	T11N-R13E, Secs. 17, 18, 19, 20	2,480	28283	1/8	Sohio Petroleum Co.	*	Sohio—100%
58	T11N-R13E, Secs. 15, 16, 21, 22	2,560	28284	1/8	Sohio Petroleum Co.	*	Sohio—100%
59	T11N-R13E, Secs. 13, 14, 23, 24	2,560	28285	1/8	Sohio Petroleum Co.	*	Sohio—100%
60	T11N-R14E, Secs. 17, 18, 19, 20	2,480	28305	1/8	Sohio Petroleum Co.	*	Sohio—100%
61	T11N-R14E, Secs. 15, 16, 21, 22	2,560	28306	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
62	T11N-R14E, Secs. 13, 14, 23, 24	2,560	28307	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
63	T11N-R15E, Secs. 17, 18, 19, 20	2,480	28321	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
64	T11N-R15E, Secs. 15, 16, 21, 22	2,560	28322	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
65	T11N-R15E, Secs. 13, 14, 23, 24	2,560	28323	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
66	T11N-R16E, Secs. 17, 18, 19	1,840	28339	1/8	Sohio Petroleum Co.	*	Sohio—100%
67	T11N-R16E, Secs. 15, 16	1,280	28340	1/8	Sohio Petroleum Co.	*	Sohio—100%
68	T11N-R16E, Secs. 13, 14	1,280	28341	1/8	Sohio Petroleum Co.	*	Sohio—100%
69	T11N-R16E, Secs. 30, 31, 32	1,851	28343	1/8	Sohio Petroleum Co.	*	Sohio—100%
70	T11N-R15E, Secs. 25, 26, 35, 36	2,560	28324	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
71	T11N-R15E, Secs. 27, 28, 33, 34	2,560	28325	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
72	T11N-R15E, Secs. 29, 30, 31, 32	2,491	28326	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
73	T11N-R14E, Secs. 25, 26, 35, 36	2,560	28308	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
74	T11N-R14E, Secs. 27, 28, 33, 34	2,560	28309	1/8	Sohio Petroleum Co.	*	Sohio—100%
75	T11N-R14E, Secs. 29, 30, 31, 32	2,491	28310	1/8	Sohio Petroleum Co.	*	Sohio—100%
76	T11N-R13E, Secs. 25, 26, 35, 36	2,560	28286	1/8	Sohio Petroleum Co.	*	Sohio—100%
77	T11N-R13E, Secs. 27, 28, 33, 34	2,560	28287	1/8	Sohio Petroleum Co.	*	Sohio—100%
78	T11N-R13E, Secs. 29, 30, 31, 32	2,491	28288	1/8	Mobil and Phillips		Mobil—50% Phillips—50%
79	T11N-R12E, Secs. 25, 26, 35, 36	2,560	28264	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%

*See comment on page A-3.

Tract No.	Description	No. of Acres	ADL Serial No.	Basic Royalty	Lessee of Record	O.R.R. Interest	Working Interest Ownership
	(Umiat Meridian, Alaska)						
80	T11N-R12E, Secs. 27, 28, 33, 34	2,560	47452	1/8	Mobil, Phillips, Chevron		Mobil—33⅓% Phillips—33⅓% Chevron—33⅓%
81	T11N-R12E, Secs. 29, 30, 31, 32	2,491	47453	1/8	Mobil, Phillips, Chevron		Mobil—33⅓% Phillips—33⅓% Chevron—33⅓%
82	T11N-R11E, Sec. 25	640	28246	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
83	T10N-R12E, Secs. 3, 4, 10	1,920	47454	1/8	Mobil, Phillips, Chevron		Mobil—33⅓% Phillips—33⅓% Chevron—33⅓%
84	T10N-R12E, Secs. 1, 2, 11, 12	2,560	28265	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
85	T10N-R13E, Secs. 6, 7, 8, S/2 and NE/4 Sec. 5	2,361	28269	1/8	Mobil and Phillips		Mobil—50% Phillips—50%
85A	T10N-R13E, NW/4 Sec. 5	160	28289	1/8	Mobil, Phillips, Chevron		Mobil—33⅓% Phillips—33⅓% Chevron—33⅓%
86	T10N-R13E, Secs. 3, 4, 9, 10	2,560	47471	1/8	Amerada Hess, et. al.		Amerada Hess—27% Getty—30.5% LL&E—13.23% Placid—9.125% N. B. Hunt—6.3625% Hunt Ind.—3.8625% Caroline Hunt Tr.—3.3% Wm. Herbert Hunt Tr.—3.3% Lamar Hunt Tr. Est.—3.3%
87	T10N-R13E, Secs. 1, 2, 11, 12	2,560	47472	1/8	Amerada Hess and Getty		Amerada Hess—50% Getty—50%
88	T10N-R14E, Secs. 5, 6, 7, 8	2,501	28313	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
89	T10N-R14E, Secs. 3, 4, 9, 10	2,560	28312	1/8	Sohio Petroleum Co.	*	Sohio—100%
90	T10N-R14E, Secs. 1, 2, 11, 12	2,560	28311	1/8	Sohio Petroleum Co.	*	Sohio—100%
91	T10N-R15E, Secs. 5, 6, 7, 8	2,501	28329	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
92	T10N-R15E, Secs. 3, 4, 9, 10	2,560	28328	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
93	T10N-R15E, Secs. 1, 2, 11, 12	2,560	28327	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
94	T10N-R16E, Secs. 5, 6, 7, 8	2,501	28345	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
95	T10N-R16E, Secs. 4, 9	1,280	28344	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
96	T10N-R16E, Sec. 16	640	28347	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%

*See comment on page A-5.

AGO 560181

Tract No.	Description	No. of Acres	ADL Serial No.	Basic Royalty	Lessee of Record	O.R.R. Interest	Working Interest Ownership
	(Umiat Meridian, Alaska)						
97	T10N-R16E, Secs. 17, 18, 19, 20	2,512	28346	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
98	T10N-R15E, Secs. 13, 14, 23, 24	2,560	28332	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
99	T10N-R15E, Secs. 15, 16, 21, 22	2,560	28331	1/8	Sohio Petroleum Co.	*	Sohio—100%
100	T10N-R15E, Secs. 17, 18, 19, 20	2,512	28330	1/8	Sohio Petroleum Co.	*	Sohio—100%
101	T10N-R14E, Secs. 13, 14, 23, 24	2,560	28315	1/8	Sohio Petroleum Co.	*	Sohio—100%
102	T10N-R14E, Secs. 15, 16, 21, 22	2,560	28314	1/8	Mobil and Phillips		Mobil—50% Phillips—50%
103	T10N-R14E, Secs. 17, 18, 19, 20	2,512	47475	1/8	Amerada Hess, et. al.		Amerada Hess—25% Getty—25% Marathon—25% Placid—7.5% N. B. Hunt—5% Hunt Ind.—3.125% Caroline Hunt Tr.—3.125% Wm. Herbert Hunt Tr.—3.125% Lamar Hunt Tr. Est.—3.125%
104	T10N-R13E, Secs. 13, 14, 24	1,920	47476	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
105	T10N-R13E, Secs. 15, 16	1,280	28290	1/8	Mobil and Phillips		Mobil—50% Phillips—50%
106	T10N-R14E, Secs. 27, 28	1,280	47482**	1/8	A.R.Co. and Exxon		A.R.Co.—50% Exxon—50%
107	T10N-R14E, Secs. 26, 36	1,280	28316	1/8	Chevron		Chevron—100%
107A	T10N-R14E, Sec. 25	640	28316	1/8	Chevron, Mobil, Phillips		Chevron—33⅓% Mobil—33⅓% Phillips—33⅓%
108	T10N-R15E, Secs. 29, 30, 31, 32	2,523	28335	1/8	Sohio Petroleum Co.	*	Sohio—100%
109	T10N-R15E, Secs. 33, 34	1,280	28334	1/8	Mobil and Phillips		Mobil—50% Phillips—50%
109A	T10N-R15E, Secs. 27, 28	1,280	28334	1/8	Mobil, Phillips, Chevron		Mobil—33⅓% Phillips—33⅓% Chevron—33⅓%
110	T10N-R15E, Secs. 25, 26, 35, 36	2,560	28333	1/8	Sohio Petroleum Co.	*	Sohio—100%
111	T10N-R16E, Secs. 29, 30, 31	1,883	28349	1/8	Sohio Petroleum Co.	*	Sohio—100%
		245,767					

*BP Alaska, Inc. owns an overriding royalty interest equal to 75% of all net profits from production between certain levels of oil production.

**This Tract Number 106 was assigned to A.R.Co. and Exxon. Upon approval of the assignment by the Director a new ADL Serial No. will be given to this Tract.

EXHIBIT "B"

Calculation of monthly in value royalty under the Leases and leases (all calculations shall be rounded to the nearest $0.001)

STEP 1: Calculate each producer's weighted average value per barrel at Point of Delivery for all oil sold by each producer during the month, as follows:

Example, Producer Y

(1) Destination	(2) Volume Sold	(3) Sales Price at Destination	(4) Shipping Costs	(5) Pipeline Tariff	(6) Point of Delivery Value	(7) Weighted Average Value
1	2,000,000	$12.500	$ -0-	$4.770	$7.730	-
2	4,000,000	13.370	1.110	4.750	7.510	-
3	5,000,000	13.440	3.830	4.750	4.860	-
						$6.345

Columns 2, 3, 4 and 5 shall be computed from actual data as reported by each producer and filed with the State of Alaska for royalty purposes ,as cross-checked against severance tax filings.

STEP 2: The "weighted average value" per barrel of each producer (column 7 above) at the Point of Delivery shall then be used in column (9) below in calculating the applicable in value price for each producer (column 11 below), the weighted average of which shall be the In Value Price to Buyer (column 12), as follows:

AGO 560183

Example, all producers:

(8) Producer and Quantity	(9) Wtd. Avg. Value at Point of Delivery (Col. 7)	(10) Wtd. Avg. Price Received by all other Producers	(11) Applicable Price for In Value Calculation	(12) In Value Price to Buyer
X; 4,200,000	$6.920	$6.404	$6.920	-
Y; 11,000,000	6.345	7.003	7.003	-
Z; 500,000	7.700	6.504	7.700	-
Weighted Avg.	$6.542			$7.003

Notes:

1) Values in column 10 are the weighted average of all producers other than the producer for which the calculation is being made.

2) Column 11 is the highest of the values in columns 9 or 10 for each producer.

3) Column 12 is the weighted average of values in column 11.

4) Buyer shall not pay any reimbursable costs under Article 8.2 until such costs are judicially determined as owing.

5) There is no posted price. "Market" or "field" value shall not be used in calculating the "In Value price to Buyer" unless and until the methodology of determining same is judicially decided.

6) Subject to later adjustment under Article 9.5.

AGO 560184

EXHIBIT "C"

FORM OF BOND

The bond shall be in a form submitted by Buyer and shall contain such terms and conditions as are approved by the Commissioner.

AGO 560185

EXHIBIT "D"

SUPPLEMENTAL ENVIRONMENTAL STANDARDS

VESSEL SAFETY AND MANEUVERABILITY FEATURES

1. Buyer agrees that all tank vessels of 1,600 gross tons or more which it owns and operates directly or through an Affiliate in marine transportation of petroleum, while navigating the coastal waters of the state, shall be equipped with the following:

(a) LORAN-C navigational equipment, or better;

(b) two marine radar systems, meeting either U. S. Marine Administration Standards for Merchant Ship Construction (COM-72-11469, Dec. 1972), or Radio Technical Commission for Marine Services performance specifications for a general purpose navigational set for ocean going ships of 1,600 tons gross tonnage and upwards (RTCM-Paper 106-75/EC-167/SC65-191 BRWG-45, or, RTCM-Paper 104-74/ED-140 BRWG 42), one of which must always be in operation, or better;

(c) those tank vessels of 20,000 DWT and over shall have at least one of the radars fitted with a collision avoidance system meeting either U. S. Maritime Administration Standards for Merchant Ship Construction (COM-72-11469, Dec. 1972), or the Radio Technical Commission for Marine Services performance specifications for a computer aided collision avoidance system for merchant ships (RTCM-Paper 171-76/EC-205/SC65-226), or better.

AGO 560186

2. Except for vessels equipped with lateral thrust equipment and astern horsepower equal to forty percent (40%) of rated horsepower, tank vessels of 20,000 DWT or more owned and operated by Buyer directly or through an Affiliate shall be escorted by tugs having an aggregate shaft horsepower equivalent to five percent of the deadweight tonnage of the escorted vessel when navigating between the Alyeska Terminal at Port Valdez and Bligh Reef, when docking at the Alyeska Terminal, and, after the Petrochemical Facility is operational, at the port facility serving the Petrochemical Facility.

BALLAST WATER TREATMENT

3. With respect to tank vessels owned and operated by Buyer directly or through an Affiliate which carry petroleum, Buyer agrees that no ballast which has been placed in cargo tanks or tank cleaning waste-water will be discharged into the waters of the state. All oily water (including, but not limited to, discharges from fuel tanks, cargo tanks, ballast tanks, slop tanks and bilges, which contain oil, grease, refined petroleum products or their by-products, including petrochemicals) discharged from any tank vessel owned and operated by Buyer directly or through an Affiliate in the State of Alaska shall be received and treated by a waste-water treatment facility meeting the effluent limitations specified in the next paragraph.

AGO 560187

4. Buyer will maintain and operate a waste-water treatment facility for the reception and treatment of ballast carried in cargo tanks and tank cleaning waste-water at or near the place where the petroleum will be transferred from the Petrochemical Facility to vessels for marine transport. Water discharged from said treatment facility shall not contain more than 10 parts of oil, grease, refined petroleum products or their by-products, including petrochemicals, per million parts of water, on a weekly (7 day) average. Buyer will consult with the Department of Fish and Game and Environmental Conservation in connection with designing and constructing said waste-water treatment facility in order that the effect of the effluent discharged from the facility on the receiving environment and the fisheries in that environment will be minimized.

PROOF OF FINANCIAL RESPONSIBILITY

5. Buyer will obtain and maintain or cause to be obtained and maintained insurance in the face amount of $20,000,000 or a corporate indemnity or guarantee of performance in an equivalent amount by a corporation or entity acceptable to the Commissioner, for each and every tank vessel owned and operated by it directly or through an Affiliate that calls at Alaskan ports and carries petroleum to compensate third parties for damages resulting from the unlawful discharge of petroleum within or affecting land or

water within the territorial jurisdiction of the State of Alaska. Buyer will also obtain and maintain insurance for each and every oil terminal facility it owns, operates or controls in Alaska, in the face amount of $100,000 for each facility with a tank capacity of less than 200,000 barrels of petroleum, and in the face amount of $1,000,000 for each facility with a tank capacity of 200,000 barrels or more of petroleum, to compensate third parties for damages resulting from the unlawful discharge of petroleum within or affecting land or water within the jurisdiction of the State of Alaska while said petroleum is being transferred. In the event any other insurance is required by applicable federal or state law to cover the same risks described in this paragraph, the face amount of any such other insurance shall be considered as a part and in reduction of the face amount of insurance required by this paragraph. The insurance shall be issued by an insurer which is either authorized to sell insurance in the State of Alaska by the Department of Commerce and Economic Development, Division of Insurance, or is an authorized insurer listed by the Division as not disapproved for use in the State of Alaska. The deductible provision in any policy of insurance, binder or certificate shall be unacceptable if it exceeds five percent (5%) of the face amount unless the Buyer demonstrates acceptable supplemental coverage or credit worthiness. The terms of the insurance shall provide that termination or cancellation of the insurance, including expiration by its terms, insofar as it relates to the insured's liability arising from a discharge of

oil within or affecting the land and water within the territorial jurisdiction of the State of Alaska, will not be effective until thirty days after notice in writing has been posted (prepaid and certified) by the insurer to the insured and to the Alaska Department of Environmental Conservation at its office in Juneau, Alaska. Buyer will annually provide the Department of Environmental Conservation (or its successor in responsibility) evidence of said insurance for the respective vessels and facilities and its coverage of said damages during the month of January.

PETROLEUM SPILL CLEANUP AND CONTINGENCY PLANS

6. Buyer shall be responsible for the detection, location, confinement and cleanup of petroleum discharges at the Petrochemical Facility. At least 180 days prior to scheduled start-up of the Petrochemical Facility, Buyer shall submit its contingency plans to the Department of Environmental Conservation for review as being in compliance with applicable law and regulation. The plans shall provide for immediate corrective action in the event of petroleum discharges, including confinement and cleanup. The plans shall include separate and specific techniques and schedules for cleanup of petroleum discharges on land and sea and in lakes, rivers, streams and estuaries, to the extent such water resources are in proximity to the Petrochemical Facility.

AGO 560190

DEFINITIONS

7. In this exhibit,

(a) "discharge" means any spilling, leaking, pumping, pouring, emitting, emptying or dumping;

(b) "DWT" or "deadweight tons" means the difference in metric tons between the lightweight displacement and the total displacement of a vessel measured in water of specific gravity 1.025 at the load waterline corresponding to the assigned summer freeboard;

(c) "oil terminal facility" means an onshore or offshore facility of any kind and related appurtenances, including but not limited to a deepwater port, located in, on, or under the surface of any land or water of the state, including title and submerged land, which is used or capable of being used for the purpose of transferring, processing or refining, or storing petroleum as it is defined in this section;

(d) "petroleum" means all crude oil purchased under this Agreement, and all refined petroleum products and petroleum by-products, including petrochemicals, produced at the Petrochemical Facility from such petroleum;

(e) "tank vessel" means a self-propelled vessel that is specially constructed or converted to carry bulk cargo in tanks and includes tankers, tankships and combination carriers;

(f) "transferred" includes both onloading and offloading between terminal and vessel; and

AGO 560191

(g) "waters of the state" means the navigable waters within the territorial limits of the State of Alaska, and the marginal sea adjacent to the State of Alaska, as defined in AS 44.03 and AS 46.03.900(22) or any successor provisions.

AMENDMENT

Dated May 17, 1978

to the

AGREEMENT FOR THE SALE AND

PURCHASE OF STATE ROYALTY OIL

THIS AMENDMENT entered into as of the 17th day of May, 1978, by and between THE STATE OF ALASKA, hereinafter called the "Seller," acting by and through its Commissioner of Natural Resources, and ALASKA PETROCHEMICAL COMPANY, an Alaska corporation, hereinafter called the "Buyer," and being the Amendment to the Agreement between Seller and Buyer entered into February 22, 1978.

WITNESSETH:

WHEREAS, an Agreement for the Sale and Purchase of State Royalty Oil was duly executed on February 22, 1978, between the State of Alaska, as Seller, and Alaska Petrochemical Company, as Buyer ("Agreement"); and

WHEREAS, the Agreement may be amended under Article XXII thereof; and

WHEREAS, Seller and Buyer desire to clarify certain intentions of the Buyer and Seller therein;

NOW THEREFORE, in consideration of the representations, covenants and conditions herein contained, Seller and Buyer hereby amend the Agreement as follows:

1. Article 1.13 is hereby amended by adding the following sentence at the end of Article 1.13:

"Total Project Costs shall not include any amounts paid for the purchase of crude oil."

2. Article I is hereby further amended by the addition of Article 1.14 which reads as follows:

"1.14 The terms "committed to be expended" as used in Article 1.13 and "commit to expend" as used in Article 10.2 shall mean contractually binding agreements, contracts and purchase orders."

3. Article 2.2 is hereby amended by the addition of a sentence at the end of such Article 2.2 as follows:

"Notwithstanding any other provision of this Article 2.2 Buyer shall not be entitled to receive delivery of any royalty crude oil hereunder until (a) Buyer has actually expended at least $100 million in Total Project Costs, and (b) at least twenty-five (25) months have passed since the Effective Date."

4. Article II is further amended by the addition of a new Article 2.7, to read as follows:

"2.7 Reduction of Quantity of Oil Deliverable to Buyer. Notwithstanding any provision of Article II requiring Seller to deliver to Buyer quantities of crude oil up to 150,000 barrels per day, in the event six years after the Effective Date the

capacity of the Petrochemical Facility is less than 150,000 barrels per day, the maximum quantities deliverable by Seller for the remaining term of this Agreement shall be reduced to that quantity equal to the capacity of the Petrochemical Facility at such time. Coincident with such reduction, the figure "145,000 barrels" appearing several places in Article 2.4 shall be reduced by a like amount. For the purposes of determining capacity under this Article 2.7, the capacity of the Petrochemical Facility shall not be diminished or reduced because of temporary reductions due to market conditions or shutdowns in the Petrochemical Facility, regardless of cause."

5. The first sentence of Article 4.2.1 is hereby amended and revised to read as follows:

"4.2.1 Construction Obligations. In consideration of the obligations assumed by each party herein, Buyer will proceed with reasonable diligence to design, construct, start up and thereafter initiate operation of a petrochemical manufacturing and fuels refining facility in the State of Alaska with capacity to process at least 150,000 barrels of crude oil per day."

IN WITNESS WHEREOF, the Seller has caused this Agreement to be executed by its Commissioner of Natural Resources and the Buyer has caused this Agreement to be executed by its

Chairman of the Board, thereunto duly authorized by its Board of Directors in accordance with the certified seal, duly attested, to be affixed hereto, as of the day and year first above written.

THE STATE OF ALASKA

ATTEST:

Frederick A. Boness

BY: Robert E. LeResche
Commissioner, Department of Natural Resources
"SELLER"

APPROVED AS TO FORM:

ALASKA PETROCHEMICAL COMPANY

ATTEST:

Richard McIntyre

BY: O. Charles Honig
Chairman of the Board
"BUYER"

AGO 560196

STATE OF ALASKA

THE LEGISLATURE

1978

Source :: SCSHCR 112

Legislative Resolve No. 42

Approving the sale of royalty oil to Alaska Petrochemical Company.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS the State of Alaska has the right under AS 38.05.-180 and its oil and gas leases to take its royalty of crude oil production removed or sold from these leases either in value (money) or in kind (oil); and

WHEREAS the legislature has, by enactment of AS 38.06 and AS 38.05.182, established a policy favoring the taking of that royalty in kind (referred to as "royalty oil"); and

WHEREAS, under his statutory authority as set out in AS 38.05 and 38.06, the commissioner of natural resources has negotiated an agreement entitled "AGREEMENT FOR THE SALE AND PURCHASE OF STATE ROYALTY OIL" ("Agreement") for the sale and purchase of royalty oil with Alaska Petrochemical Company; and

WHEREAS, under its duties and powers as set out in AS 38.06, the Alaska Royalty Oil and Gas Development Advisory Board has considered and, on February 22, 1978, approved the Agreement; and

WHEREAS the commissioner of natural resources has fulfilled the statutory prerequisites necessary to selling the royalty oil which is the subject of the Agreement and has obtained approvals from the Alaska Royalty Oil and Gas Development Advisory Board, to the extent required under AS 38.05 and 38.06; and

WHEREAS the Agreement contains a provision stating that it takes effect on the date on which it has been approved by a concurrent resolution of a majority of each house of the Tenth Alaska State Legislature; and

WHEREAS, under AS 38.06.055(a), no sale of royalty oil may be made by the commissioner of natural resources without the prior approval of the legislature by a concurrent resolution concurred in by a majority of the members of each house; and

WHEREAS the commissioner of natural resources submitted the Agreement to the legislature for consideration and approval; and

WHEREAS the legislature has reviewed and evaluated the Agreement, and has conducted public hearings and otherwise received background information, expert advice, and expressions of public opinion sufficient to make a reasoned determination with respect to the Agreement; and

WHEREAS the commissioner of natural resources and Alaska Petrochemical Company have negotiated certain amendments to the Agreement, dated May 17, 1978; and

WHEREAS the Royalty Oil and Gas Development Advisory Board has considered and, on May 19, 1978, approved those amendments; and

WHEREAS the legislature finds the Agreement, as amended, to be in the best interest of the State of Alaska and its citizens, and further finds that the Agreement, as amended, is in compliance with all applicable constitutional directives and requirements of law;

BE IT RESOLVED by the Alaska State Legislature that the agreement entitled "AGREEMENT FOR THE SALE AND PURCHASE OF STATE ROYALTY OIL," as amended, between the State of Alaska, acting through its commissioner of natural resources, and Alaska Petrochemical Company, is hereby approved.

AGO 560198

Authentication

The following officers of the Legislature certify that the attached enrolled resolution, SENATE CS FOR HOUSE CONCURRENT RESOLUTION NO. 112, was passed in conformity with the requirements of the constitution and laws of the State of Alaska and the Uniform Rules of the Legislature.

Passed by the House June 18, 1978

Speaker of the House

ATTEST:

Chief Clerk of the House

Passed by the Senate June 13, 1978

President of the Senate

ATTEST:

Secretary of the Senate

AGO 560199

AGO 560200

Research Office Copy

AMENDMENT

Dated May 17, 1978

to the

AGREEMENT FOR THE SALE AND PURCHASE OF STATE ROYALTY OIL

Legislative Reference Library
Legislative Affairs Agency
State Capital
Pouch Y
Juneau, AK 99811

THIS AMENDMENT entered into as of the 17th day of May, 1978, by and between THE STATE OF ALASKA, hereinafter called the "Seller," acting by and through its Commissioner of Natural Resources, and ALASKA PETROCHEMICAL COMPANY, an Alaska corporation, hereinafter called the "Buyer," and being the Amendment to the Agreement between Seller and Buyer entered into February 22, 1978.

WITNESSETH:

WHEREAS, an Agreement for the Sale and Purchase of State Royalty Oil was duly executed on February 22, 1978, between the State of Alaska, as Seller, and Alaska Petrochemical Company, as Buyer ("Agreement"); and

WHEREAS, the Agreement may be amended under Article XXII thereof; and

WHEREAS, Seller and Buyer desire to clarify certain intentions of the Buyer and Seller therein;

NOW THEREFORE, in consideration of the representations, covenants and conditions herein contained, Seller and Buyer hereby amend the Agreement as follows:

1. Article 1.13 is hereby amended by adding the following sentence at the end of Article 1.13:

"Total Project Costs shall not include any amounts paid for the purchase of crude oil."

2. Article I is hereby further amended by the addition of Article 1.14 which reads as follows:

"1.14 The terms "committed to be expended" as used in Article 1.13 and "commit to expend" as used in Article 10.2 shall mean contractually binding agreements, contracts and purchase orders."

3. Article 2.2 is hereby amended by the addition of a sentence at the end of such Article 2.2 as follows:

"Notwithstanding any other provision of this Article 2.2 Buyer shall not be entitled to receive delivery of any royalty crude oil hereunder until (a) Buyer has actually expended at least $100 million in Total Project Costs, and (b) at least twenty-five (25) months have passed since the Effective Date."

4. Article II is further amended by the addition of a new Article 2.7, to read as follows:

"2.7 Reduction of Quantity of Oil Deliverable to Buyer. Notwithstanding any provision of Article II requiring Seller to deliver to Buyer quantities of crude oil up to 150,000 barrels per day, in the event six years after the Effective Date the

capacity of the Petrochemical Facility is less than 150,000 barrels per day, the maximum quantities deliverable by Seller for the remaining term of this Agreement shall be reduced to that quantity equal to the capacity of the Petrochemical Facility at such time. Coincident with such reduction, the figure "145,000 barrels" appearing several places in Article 2.4 shall be reduced by a like amount. For the purposes of determining capacity under this Article 2.7, the capacity of the Petrochemical Facility shall not be diminished or reduced because of temporary reductions due to market conditions or shutdowns in the Petrochemical Facility, regardless of cause."

5. The first sentence of Article 4.2.1 is hereby amended and revised to read as follows:

"4.2.1 Construction Obligations. In consideration of the obligations assumed by each party herein, Buyer will proceed with reasonable diligence to design, construct, start up and thereafter initiate operation of a petrochemical manufacturing and fuels refining facility in the State of Alaska with capacity to process at least 150,000 barrels of crude oil per day."

IN WITNESS WHEREOF, the Seller has caused this Agreement to be executed by its Commissioner of Natural Resources and the Buyer has caused this Agreement to be executed by its

Chairman of the Board, thereunto duly authorized by its Board of Directors in accordance with the certified seal, duly attested, to be affixed hereto, as of the day and year first above written.

THE STATE OF ALASKA

ATTEST:

BY:
Commissioner, Department of Natural Resources
"SELLER"

APPROVED AS TO FORM:

ALASKA PETROCHEMICAL COMPANY

ATTEST:

BY:
Chairman of the Board
"BUYER"

AGO 560204

Witton

SECOND AMENDMENT

Dated May 30, 1980

to the

AGREEMENT FOR THE SALE AND

PURCHASE OF STATE ROYALTY OIL

THIS SECOND AMENDMENT entered into as of the 30th day of May, 1980, by and between THE STATE OF ALASKA, hereinafter called the "Seller," acting by and through its Commissioner of Natural Resources, and THE ALPETCO COMPANY, a Florida general partnership, hereinafter called the "Buyer", and being the Second Amendment to the Agreement between Seller and Alaska Petrochemical Company entered into February 22, 1978, and assigned by Alaska Petrochemical Company to Buyer by an assignment executed December 13, 1979, and approved by Seller on February 4, 1980.

WITNESSETH:

WHEREAS, an Agreement for the Sale and Purchase of State Royalty Oil was duly executed on February 22, 1978, was amended on May 17, 1978, and was assigned to Buyer pursuant to an assignment executed December 13, 1979, and approved by Seller on February 4, 1980 (the "Agreement"); and

WHEREAS, the Agreement may be amended under Article XXII thereof; and

WHEREAS, Seller and Buyer desire to reduce the amount of crude oil that Seller must sell to Buyer under the Agreement; and

WHEREAS, Seller and Buyer desire that certain provisions of the Agreement be amended to clarify the obligations of Seller and Buyer thereunder;

NOW THEREFORE, in consideration of the mutual agreements and undertakings provided herein, Seller and Buyer hereby agree as follows:

1. The first Whereas clause on page 1 of the Agreement is hereby amended to read in its entirety as follows:

> "WHEREAS, it is in the mutual best interests of Seller and Buyer that Buyer construct and operate a facility in Alaska to process oil sold hereunder, said facility to have the capacity to process approximately 100,000 barrels of crude oil per stream day and to produce at least approximately 30,000 barrels per day of energy fuels for in-state distribution and sale; and"

2. Article I is hereby amended by deleting Articles 1.12, 1.13 and 1.14, renumbering Articles 1.6 through 1.11 to be Articles 1.7 through 1.12 and adding the following new Article 1.6:

> "1.6 'Facility' shall have the meaning defined in Article 4.2.1."

AGO 560206

3. Each reference in the Agreement to "Petrochemical Facility" is hereby changed to "Facility."

4. Article 2.1 is hereby amended and restated in its entirety to read as follows:

"2.1 Sale of Prudhoe Bay Royalty Oil. Subject to the terms and conditions hereinafter provided, and subject to the prior obligations of Seller to deliver 5,000 barrels of crude oil per day under its contract with Golden Valley Electric Association, Inc. ("Golden Valley"), for the term and in the quantity now stated therein, Seller agrees to sell to Buyer, and Buyer agrees to buy from Seller, on the average, determined on an annual basis, approximately 75,000 barrels per day from Seller's royalty oil out of the crude oil production removed or sold from the Leases which the Seller has the right to take and is available to the Seller for taking in kind. However, in the event that 75,000 barrels per day of royalty oil is greater than 85% of Seller's royalty oil, then Seller shall be obligated to deliver said lesser quantity. Seller shall nominate that

percentage of its royalty oil from the Leases which shall equal approximately 75,000 barrels per day on the average, except as provided in the preceding sentence. If total production from the Leases changes such that Seller's nomination results in Seller receiving from the Leases less than 75,000 barrels per day determined on an annual basis, then Seller, as expeditiously as possible (and subject to the terms of the Prudhoe Bay Unit Agreement if applicable), shall adjust its nomination to equal 75,000 barrels per day (except that Seller shall not be required to nominate more than 85% of Seller's royalty oil for sale to Buyer). Subject to the further provisions of this Article 2.1, Seller reserves the right to use or dispose of the remaining royalty oil. After the completion of the Facility, Seller's obligations to Golden Valley, if any, shall first be satisfied out of the royalty oil from the Leases not being sold to Buyer hereunder. In addition to the crude oil deliverable under the other provisions of this Article 2.1,

Buyer shall also possess the option to purchase an additional five percent (5%) of the total amount of Seller's royalty oil out of the Leases:

(a) in the event Seller enters into a contract with North Pole Refining Company ("NPR") granting NPR an option to purchase part or all of the fifteen percent (15%) portion of the oil out of the Leases not sold to Buyer under other provisions of this Article 2.1 and NPR does not exercise its option in full to purchase the oil on which it has an option, but Buyer's option to purchase shall extend only to the purchase of that quantity of oil from time to time not purchased by NPR: or

(b) in the event Seller does not enter into or have in effect a contract with NPR as recited in Article 2.1(a).

In the event it exercises its option under Article 2.1(a) or 2.1(b) above, Buyer agrees to give Seller an additional thirty (30) days notice of any

nominations under this Article in addition to the time for notice specified in the Prudhoe Bay Unit Agreement. In the event under any agreement with NPR Seller obtains a right to purchase from NPR any oil returned to the Trans Alaska Pipeline System by NPR, Seller shall assign all such rights to Buyer for the term of such NPR agreement.

Seller represents to Buyer that it has obtained sufficient advance written consents to termination and an agreement from Lessees (which to Seller's knowledge has been performed) to require similar consents from all subsequent purchasers agreeing to waive or terminate any supplier-purchaser relationship as to sufficient quantities of Seller's royalty crude oil out of the Leases to enable Seller to perform its delivery obligations under this Agreement.

Notwithstanding the foregoing provisions of this Article 2.1, Seller shall sell to Buyer approximately 100,000 barrels per day on the average, determined on an annual basis, after Buyer has begun processing crude oil in

the Facility, except that if 85% of Seller's royalty oil is less than 100,000 barrels per day then Seller shall be obligated to sell to Buyer only said lesser amount."

5. Article 2.2 is hereby amended and restated in its entirety to read as follows:

"2.2 Initiation of First Delivery. Buyer shall take delivery of crude oil under this Agreement beginning July 18, 1980. Buyer agrees that it shall fully comply with its obligations under Article 26.6."

6. Article 2.3 is hereby amended by replacing the words "ninety percent (90%)" in the first sentence thereof with the words "sixty percent (60%)," replacing the words "ten percent (10%)" in the fourth sentence thereof with the words "forty percent (40%)" and replacing the number "150,000" with the number "100,000" in the third from the last sentence thereof.

7. Article 2.4 is hereby amended by replacing the numbers "145,000" and "150,000" with the numbers "95,000" and "100,000," respectively, in each place that they appear in such Article, and replacing the words "seventy percent (70%)" in the first and third sentences thereof with the words "fifty percent (50%)."

8. Article 2.5 is hereby amended by replacing the number "150,000" with the words "75,000 or 100,000, as the case may be," in the first sentence thereof.

9. Article 2.6 is hereby amended by replacing the words "on or prior to" in the third line thereof with the words "commencing on" and inserting after the words "Date of First Delivery" in the fourth line thereof the following words:

", and shall maintain at all times thereafter,"

10. Article 2.7 is hereby amended and restated to read in its entirety as follows:

"2.7 Reduction of Quantity of Oil Deliverable to Buyer. Notwithstanding any provision of Article II requiring Seller to deliver to Buyer quantities of crude oil up to 100,000 barrels per day, in the event that on or before December 31, 1985, the designed capacity of the Facility is less than 100,000 barrels per stream day, the maximum quantities deliverable by Seller for the remaining term of this Agreement shall be reduced to that quantity equal to the designed capacity of the Facility at such time. Coincident with such reduction, the figure '95,000 barrels' appearing

several places in Article 2.4 shall be reduced by a like amount."

11. A new Article 2.8 is hereby added as follows:

"2.8 Nomination of Crude Oil. It is expressly recognized that as to royalty oil out of the Leases, and perhaps to royalty oil on future production, the Seller may only nominate its royalty oil by percentage, and not by a fixed amount of barrels. Therefore, whenever the Seller is to deliver, and Buyer is to receive, a fixed number of barrels, either "75,000" or "100,000", it is understood that Seller can only nominate a percentage of its royalty share that, upon the best information available to Seller, will equate approximately to the fixed number of barrels to be delivered. For example, it is recognized that fluctuation in production may sometimes cause the existing percentage nomination to differ substantially from the fixed number of barrels required herein. If there is a significant change in production, Seller shall be obligated only to increase or decrease its royalty percentage pursuant to Lease

or Prudhoe Bay Unit procedures so as to again approximately equate to the fixed number of barrels required. In addition, and as another example, it is also expected that temporary increases or decreases in production will result in deliveries hereunder to fluctuate around the fixed number of barrels set forth herein."

12. Article 4.2.1 is hereby amended and restated in its entirety to read as follows:

"4.2.1 Construction Obligations. In consideration of the obligations assumed by each party herein, upon approval by the Commissioner pursuant to Article 10.2 hereof Buyer will proceed with diligence to construct, start up and thereafter initiate operation of a facility in the State of Alaska with capacity to process approximately 100,000 barrels of crude oil per stream day substantially in accordance with the schedule presented to the Commissioner pursuant to Article 10.2 hereof. Such facility shall include substantially all of the facilities approved by the Commissioner pursuant to Article 10.2

AGO 560214

hereof. Incidental changes and modifications of the facilities prior to start-up may be made without the consent of the Commissioner, but any major changes in the facilities prior to start-up must be approved by the Commissioner. Final process configuration and production rates from the facility will be determined by (i) marketing considerations and (ii) process optimization of the overall facility design to produce the desired products in the most effective manner. Variations in design, configuration and process optimization will occur throughout the anticipated life of the facility. Such facilities shall be hereinafter referred to as the 'Facility.'"

13. Article 4.2.3 is hereby amended and restated in its entirety to read as follows:

"4.2.3 Progress Reports by Buyer. From the date of the Second Amendment and until December 31, 1981 (and thereafter until the start-up of the Facility if the Commissioner gives his approval pursuant to Article 10.2 hereof) on or before the twentieth (20th) day after

each calendar quarter, Buyer shall furnish the Commissioner a written progress report as of the end of such calendar quarter describing its progress on the engineering, design and construction activities of Buyer with respect to the Facility, progress in the marketing of the products therefrom and the proposed financings. Such reports, or portions thereof, shall be held confidential as requested by Buyer to the extent permitted by law."

14. Article 4.4 is hereby amended by deleting the words "fuels and petrochemical" from the fourth sentence thereof.

15. Article 10.2 is hereby amended and restated in its entirety to read as follows:

"10.2 Termination by Seller. Notwithstanding anything else to the contrary in this Agreement, this Agreement shall terminate and Seller shall have no further obligation to deliver any further crude oil to Buyer (i) upon failure of Buyer to proceed with reasonable diligence pursuant to the provisions of Article 4.2.1 or Article 10.2.1 or

(ii) 30 days after the disapproval by the Commissioner of the Facility pursuant to the provisions of this Article 10.2.2, except that Buyer pursuant to Article 14.2 shall have the obligation to purchase royalty oil if Seller elects to sell such oil to Buyer.

10.2.1 Buyer's Obligations. Buyer promptly after the date of the Second Amendment shall proceed with reasonable diligence to do the following:

(a) configure, engineer and design the Facility, which shall have a capacity to process at least 100,000 barrels of crude oil per stream day;

(b) obtain all financing necessary to pay for the construction of the Facility including entering into all definitive documents relating to the loan of funds that are necessary to finance the costs of construction of the Facility;

(c) enter into all construction contracts that

are necessary to provide for the construction of the Facility;

(d) provide a construction schedule and completion date for the construction of the Facility;

(e) obtain all material permits and licenses relating to the Facility that are necessary for the construction of the Facility; and

(g) enter into all leases of real property for the site of the Facility.

10.2.2 Commissioner's Approval. On or before December 31, 1981, Buyer shall provide to the Commissioner documents evidencing Buyer's diligence in proceeding to do all of the foregoing. If within 60 days from submission of the documents, the Commissioner determines that such documents do not demonstrate completion of each of the items listed in Article 10.2.1, the Commissioner may terminate this Agreement by giving thirty (30) days' notice to

AGO 560218

Buyer. If all of the foregoing have been completed, the Commissioner shall have sixty (60) days from submission of the documents to review them and either approve or disapprove the Facility. The approval shall be at the sole and absolute discretion of the Commissioner. Upon approval, Buyer shall construct the Facility in compliance with Article 4.2.1 hereof. Thirty (30) days after disapproval by the Commissioner this Agreement shall terminate and Buyer shall have no further right whatsoever to receive any crude oil from Seller, except that Buyer, pursuant to Article 14.2 shall have the obligation to purchase royalty oil if Seller elects to sell such oil to Buyer.

10.2.3 Facility Start-up. If Buyer has not begun processing crude oil in the Facility on or before March 1, 1986, the Commissioner may terminate this Agreement including any obligation to make any further deliveries of crude oil on March 31, 1986, or at any time thereafter by giving notice of termination

AGO 560219

to Buyer prior to start-up of the Facility."

16. Article 14.1 is hereby amended by deleting from the third line of clause (ii) thereof the words "into petrochemicals."

17. Article 16.1 is hereby amended by deleting the address of Buyer and replacing it with the following addresses:

"The Alpetco Company
601 W. 5th Avenue, #320
Anchorage, Alaska 99501

and
The Alpetco Company
3700 Buffalo Speedway
Houston, Texas 77098"

18. Article 23.2 is hereby amended by deleting the third sentence thereof.

19. Article 26.7 is hereby amended by replacing the words "extensions of time periods" with the word "approvals."

20. Seller and Buyer hereby ratify and confirm all provisions of the Agreement, as amended by this Second Amendment.

21. Seller and Buyer each hereby represent and warrant to each other that it has full power and authority to execute, deliver and perform this Second Amendment and that this Second Amendment, and the Agreement as amended by this Second Amendment, constitute valid and binding obligations of such party and are enforceable against such party in accordance with their terms.

AGO 560220

22. The Agreement as amended by this Second Amendment shall become effective upon its due execution and delivery by each of Seller and Buyer and if approved by the Alaska Royalty Oil and Gas Development Board and the Alaska State Legislature, to the extent such approvals are required by Article XXII of the Agreement. This Second Amendment shall be null and void if it is not so approved on or before June 7, 1980.

IN WITNESS WHEREOF, the Seller has caused this Second Amendment to be executed by its Commissioner of Natural Resources and the Buyer has caused this Second Amendment to be executed by its General Manager as of the day and year first above written.

THE STATE OF ALASKA

ATTEST:

_____ BY: _____
Commissioner, Department of Natural Resources

APPROVED AS TO FORM:

_____

THE ALPETCO COMPANY

ATTEST:

_____ BY: _____
General Manager

I, Frank M. Smith, certify that I am the Vice President of the Buyer in the above contract, that Dudley K. Parker was then General Manager of said Buyer, that said Agreement was duly signed for and in behalf of Buyer by authority of its governing body, and is within the scope of its powers.

_____
Vice President

(CORPORATE SEAL)

THE STATE OF ALASKA)
) ss.
FIRST JUDICIAL DISTRICT)

THIS IS TO CERTIFY that on this 30th day of May, 1980, before me, the undersigned, a Notary Public in and for the State of Alaska, duly commissioned and sworn as such, personally appeared Robert E. LeResche, to me known to be the Commissioner of Natural Resources for the STATE OF ALASKA, and known to me to be the person who executed the within instrument on behalf of the STATE OF ALASKA, and acknowledged to me that the same was signed as a free act and deed of the STATE OF ALASKA for the purposes and uses therein stated.

WITNESS my hand and notarial seal the day and year last above written.

_____
NOTARY PUBLIC in and for Alaska.
My commission expires: _____

THE STATE OF ALASKA)
) ss.
FIRST JUDICIAL DISTRICT)

THIS IS TO CERTIFY that on the 30th day of May, 1980, before me, the undersigned, a Notary Public in and for the State of Alaska, duly commissioned and sworn as such, personally appeared the General Manager of THE ALPETCO COMPANY, a Florida general partnership, and known to me to be the person who executed the within instrument on behalf of the partnership herein named, and acknowledged to me that the same was signed as a free act and deed of said partnership for the uses and purposes therein stated and pursuant to its authority.

WITNESS my hand and notarial seal the day and year last above written.

NOTARY PUBLIC in and for Alaska.
My commission expires: _____

Royalty Bd?

Leg. Appsal?

AGO 560223