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ON

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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 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.

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 inner mortar 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- -- 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 th 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 comewhat 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 litho-logic 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 reservoir 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

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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 re 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

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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 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 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 modes 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 do you 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.

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 barrel~, 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 man, n-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 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 completely 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 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?

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 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

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. - simultaneous 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;

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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, 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 drainage 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 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~~ criptions 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 aquiter?

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 hydro-carbon 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

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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 adifferent 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 million 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 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 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 additiona 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 baseline 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 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 trunkation 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 affected.

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 interval. 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......

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 lik 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 an aquifer 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 pretroleum 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~~ pressure 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 ıe 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 were sophisticated 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

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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 o 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 copies 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, dependi-g 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.

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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 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.

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Joint Gas Pipeline Committee
Alaska State Legislature

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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

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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.

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

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(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

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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

Todd M. Doscher

TMD/jak
Enclosure

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

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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.

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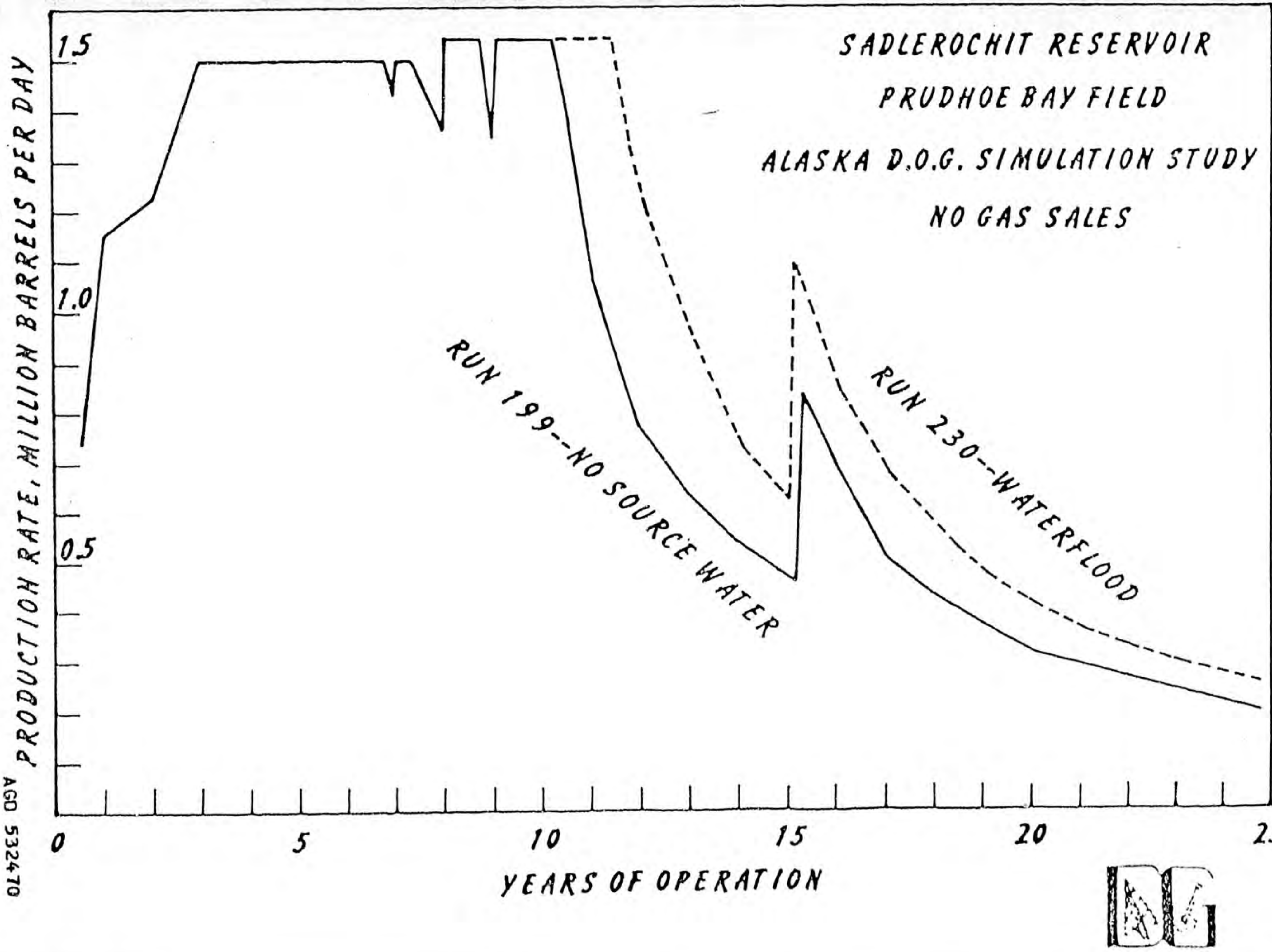
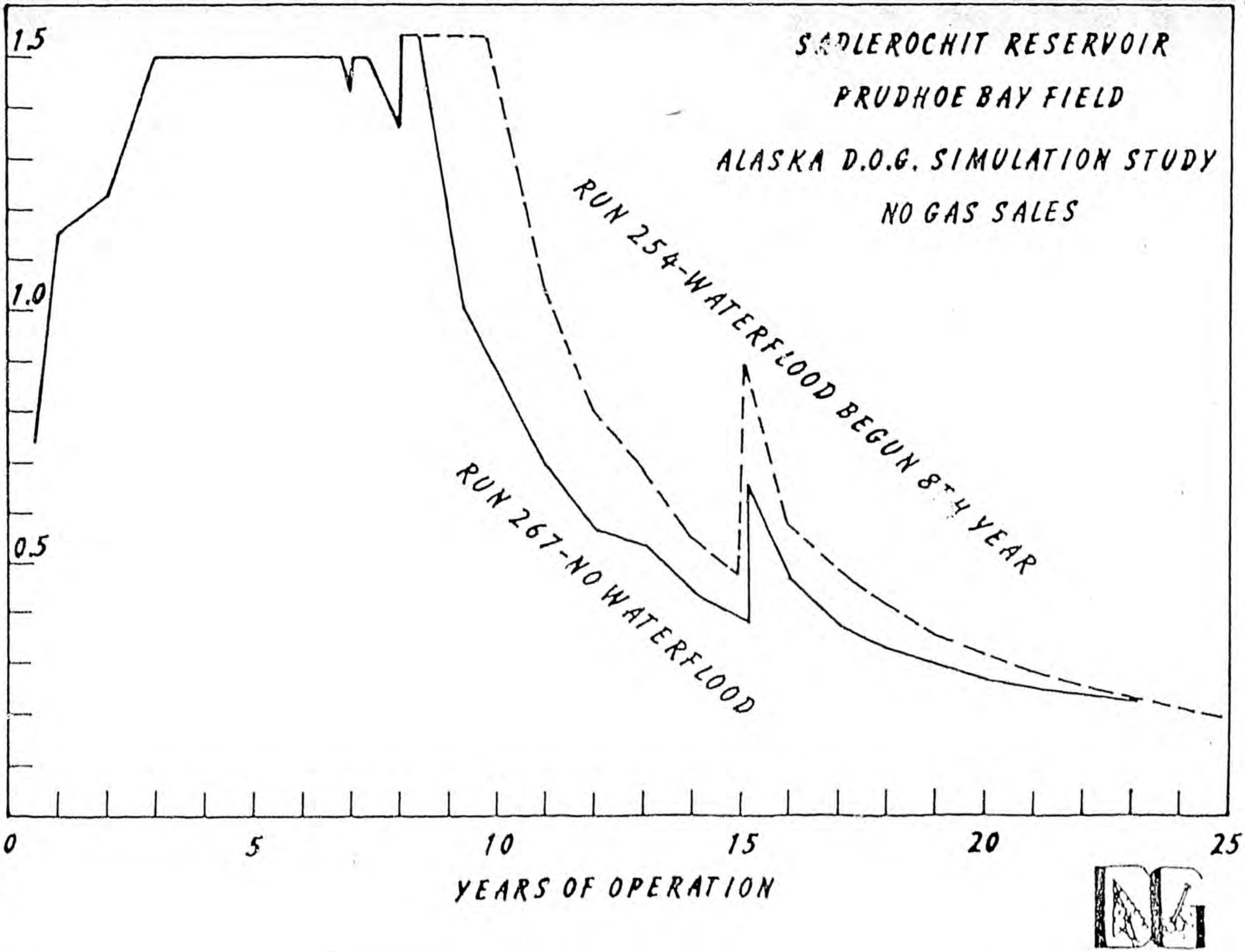

SADLEROCHIT RESERVOIR
PRUDHOE BAY FIELD
ALASKA D.O.G. SIMULATION STUDY
NO GAS SALES
PRODUCTION RATE, MILLION BARRELS PER DAY
1.5
1.0
0.5
RUN 199--NO SOURCE WATER
RUN 230--WATERFLOOD
0
5
10
15
20
25
YEARS OF OPERATION

AGO 532470



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

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.)

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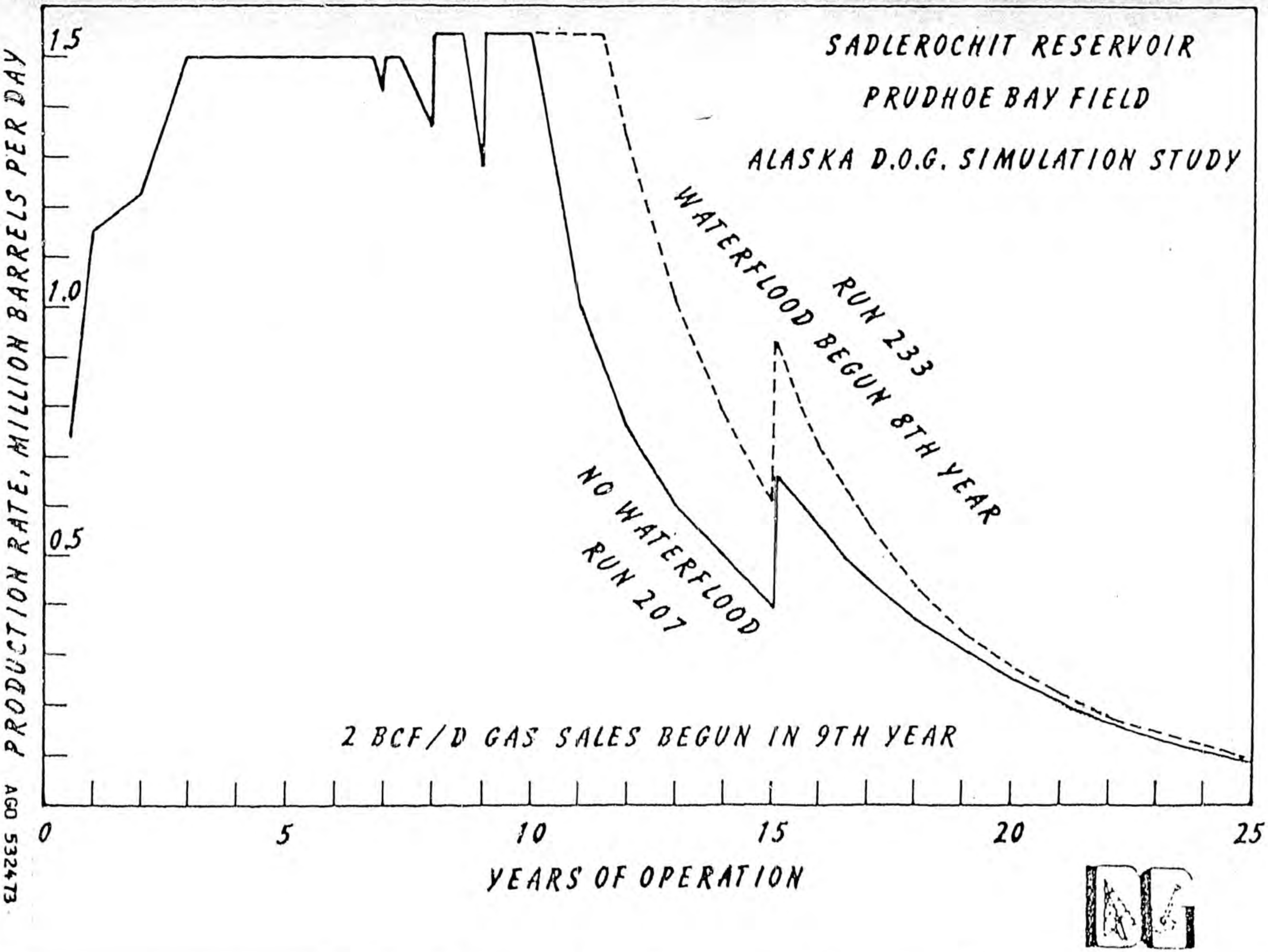
SADLEROCHIT RESERVOIR
PRUDHOE BAY FIELD
ALASKA D.O.G. SIMULATION STUDY
WATERFLOOD BEGUN 8TH YEAR
RUN 233
NO WATERFLOOD
RUN 207
2 BCF/D GAS SALES BEGUN IN 9TH YEAR
PRODUCTION RATE, MILLION BARRELS PER DAY
1.5
1.0
0.5
0
5
10
15
20
25
YEARS OF OPERATION
AGO 53243

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%.

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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

AGO 532475

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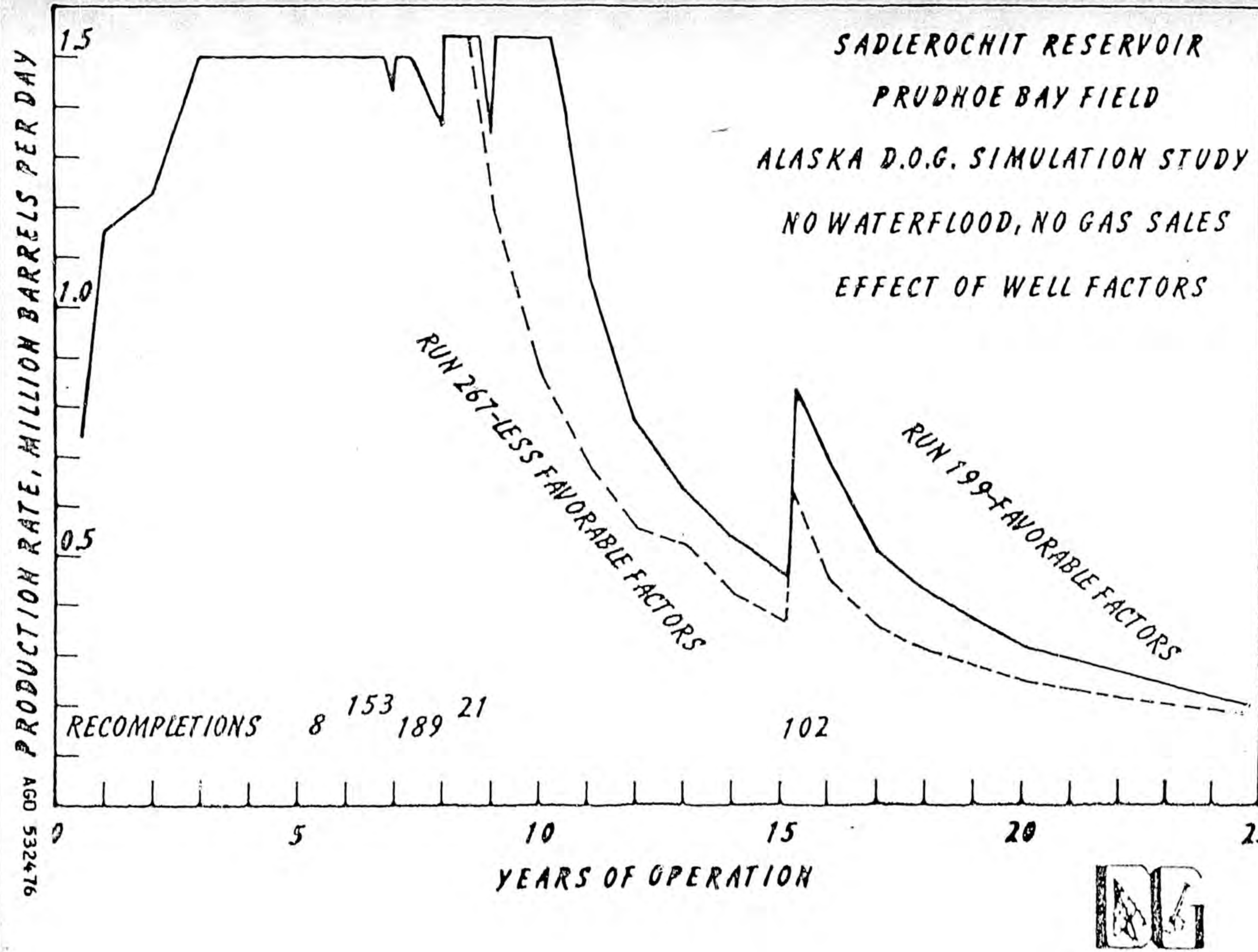
SADLEROCHIT RESERVOIR
PRUDHOE BAY FIELD
ALASKA D.O.G. SIMULATION STUDY
NO WATERFLOOD, NO GAS SALES
EFFECT OF WELL FACTORS
PRODUCTION RATE, MILLION BARRELS PER DAY
1.5
1.0
0.5
RUN 267-LESS FAVORABLE FACTORS
RUN 199-FAVORABLE FACTORS
RECOMPLETIONS 8 153 189 21
102
0
5
10
15
20
25
YEARS OF OPERATION
AGO 532476

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.

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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

Todd M. Doscher.

OBJECTIVES

evaluate oil recovery

with or without source water injection

with or without gas sales

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~~ 6 billion bbls

solution gas __________ 14.9 trillion cf

gas cap gas __________ 23.4 trillion cf

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

* 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

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

Exhibit 6, H. K. van Poollen and Associates, Inc. 2/8/80

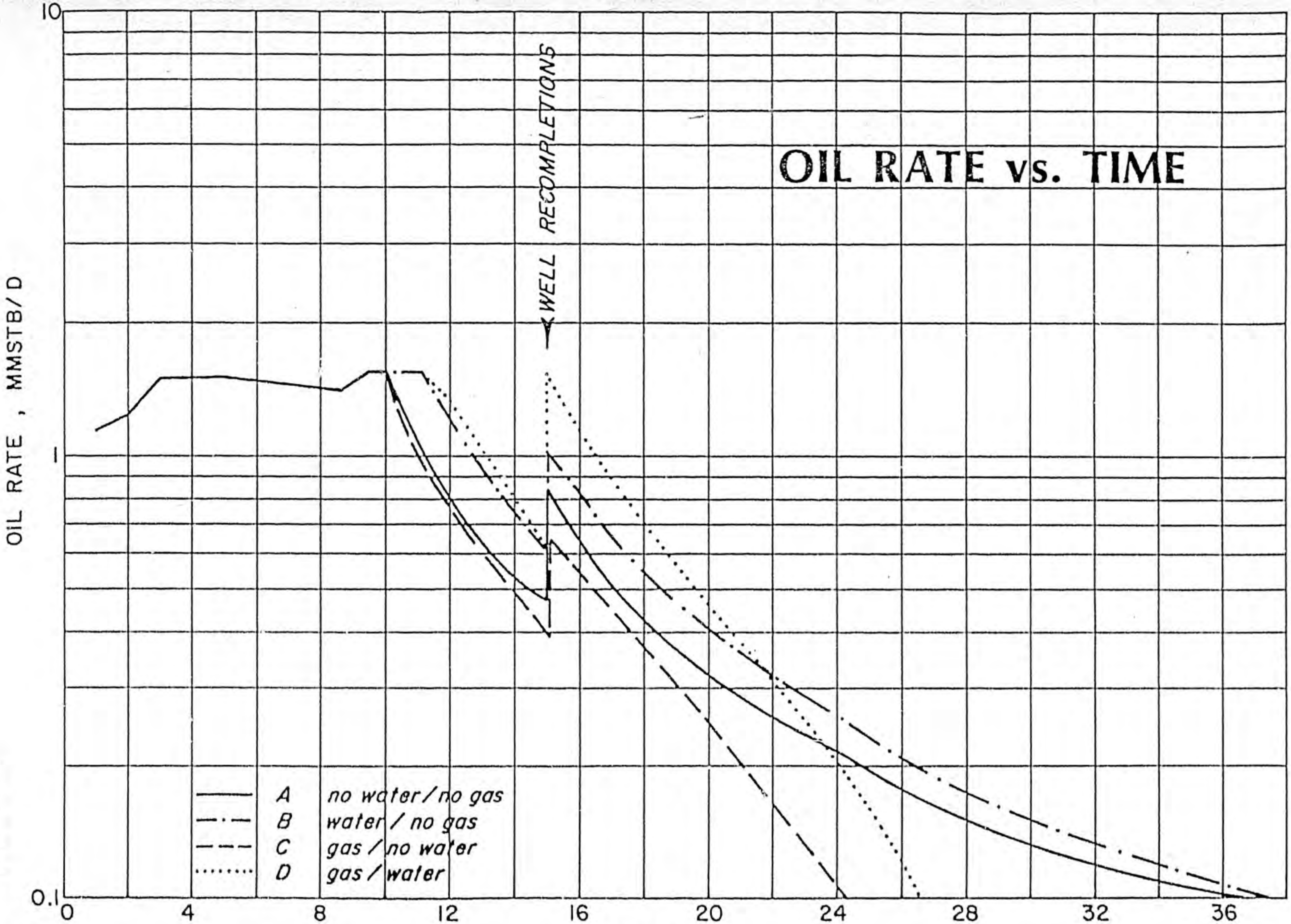


Exhibit 7, H. K. van Poollen and Associates, Inc. 2/8/80

AGO 532486

OIL RATE vs. RECOVERY

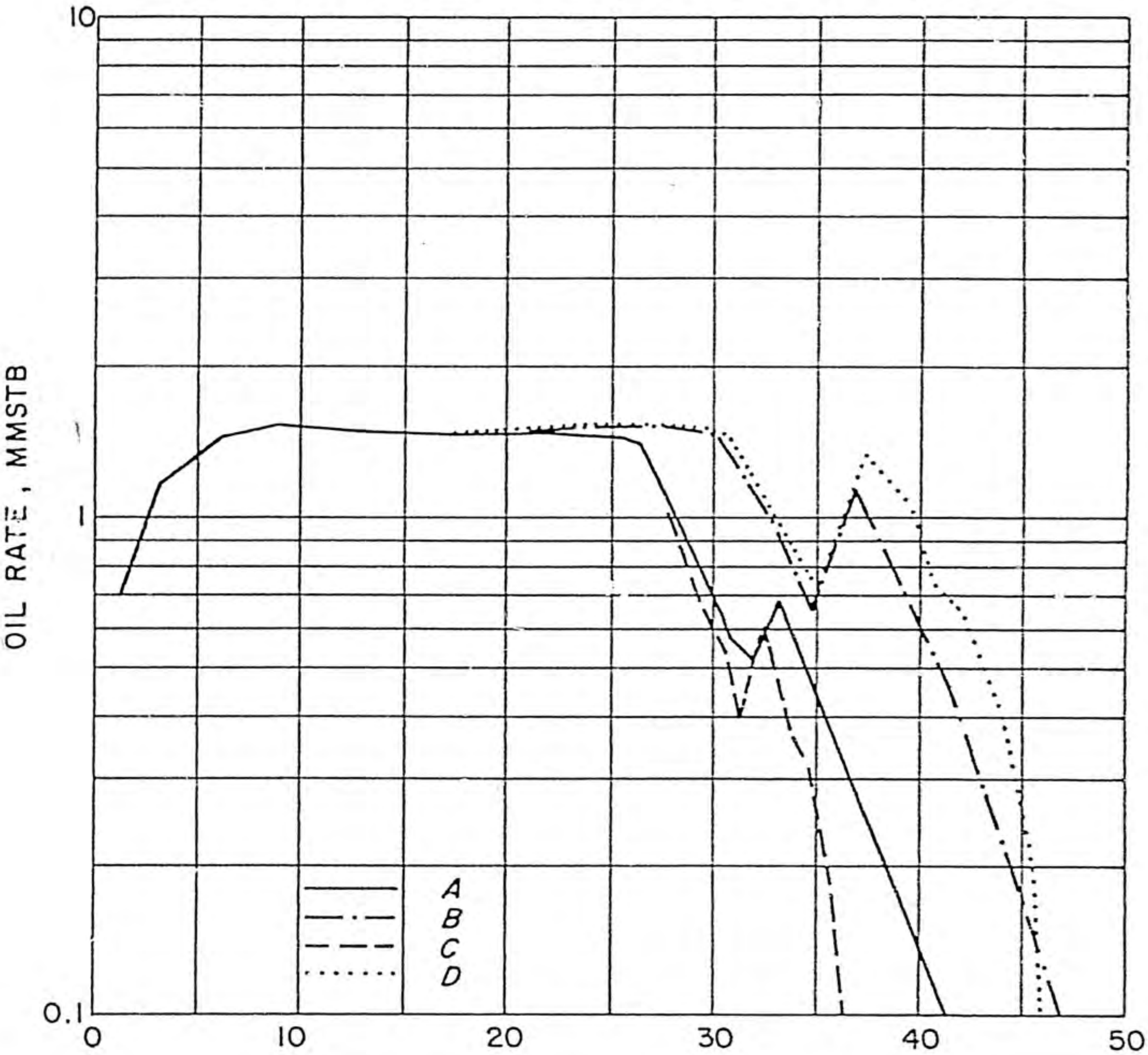


Exhibit 8, H. K. van Poollen and Associates, Inc. 2/8/80

AGO 532487

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.

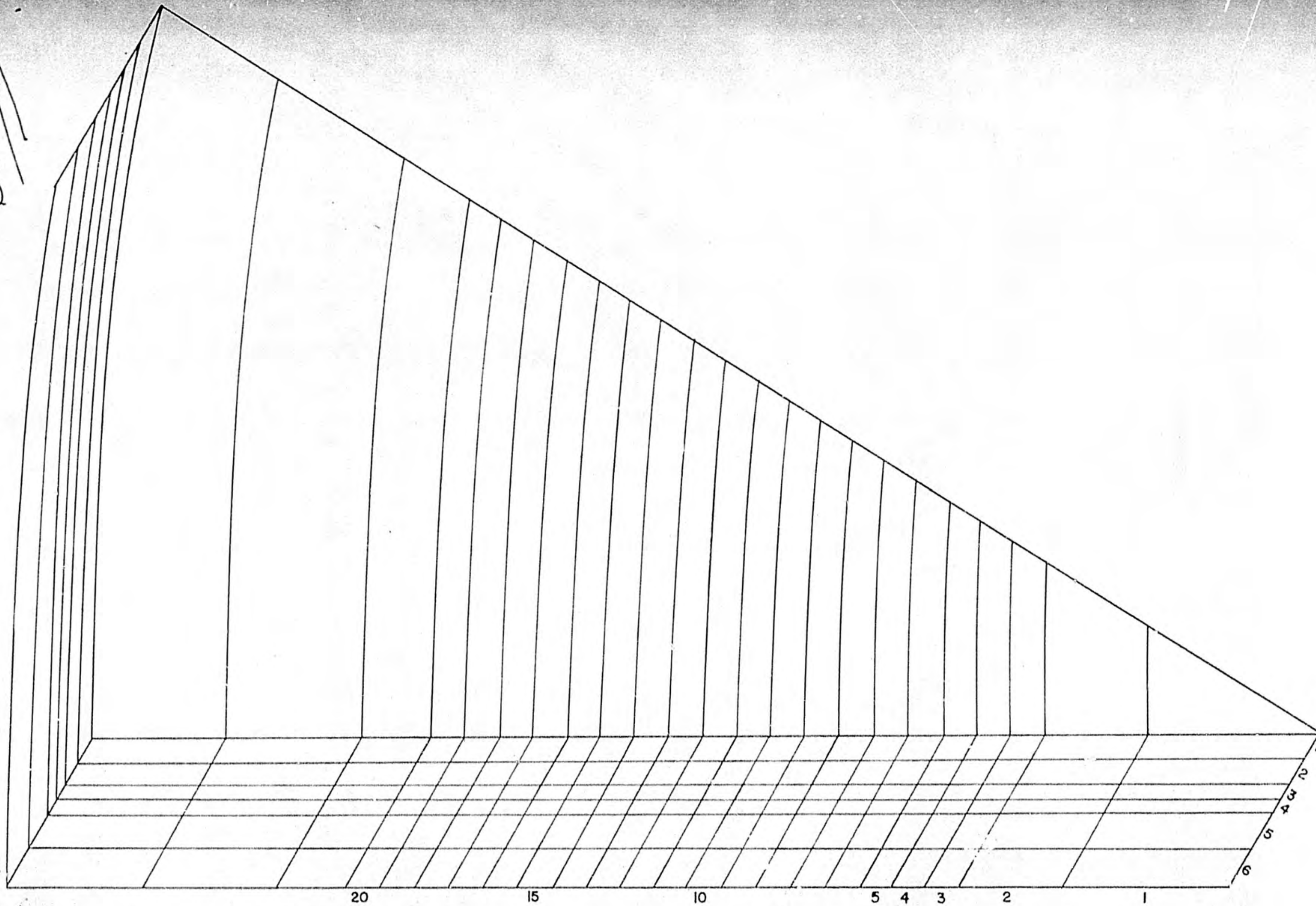
THE INTERACTION OF FORCES BETWEEN ROCK AND FLUIDS ARE GIVEN BY THE FOLLOWING SATURATION DEPENDENT FUNCTIONS:

- RELATIVE OIL PERMEABILITY.
- RELATIVE WATER PERMEABILITY.
- RELATIVE GAS PERMEABILITY.
- CAPILLARY PRESSURE BETWEEN OIL AND WATER
- CAPILLARY PRESSURE BETWEEN GAS AND OIL.

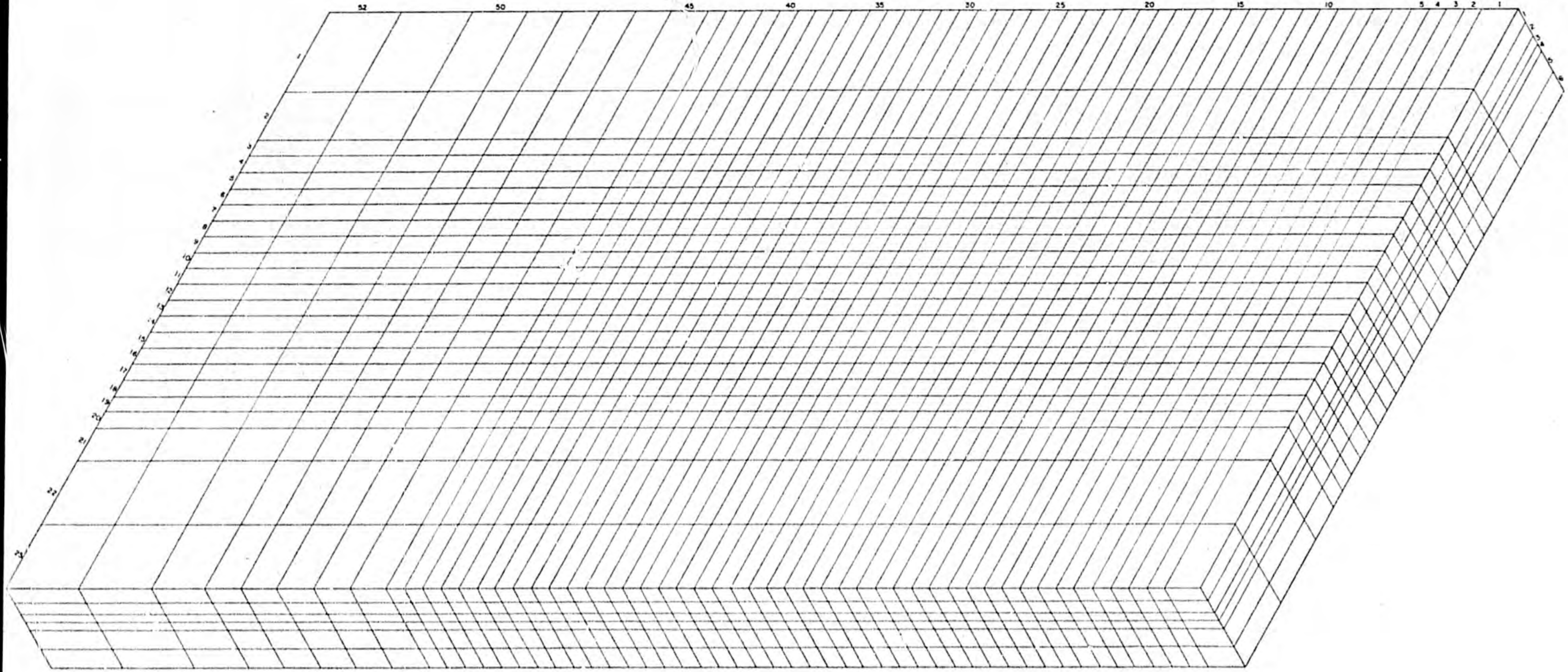
SPECIFIC WELL DATA FOR APPROPRIATE GRID NODES AS FOLLOWS:

- PRODUCING INTERVAL.
- OIL PRODUCTION RATE VS. TIME.
- WATER PRODUCTION RATE VS. TIME.
- GAS PRODUCTION RATE VS. TIME.
- OBSERVED PRESSURES VS. TIME.

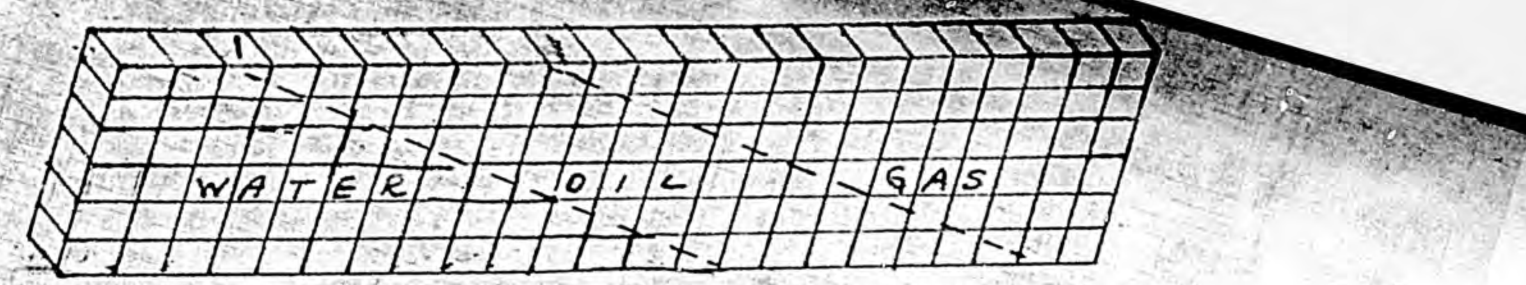
Coletta



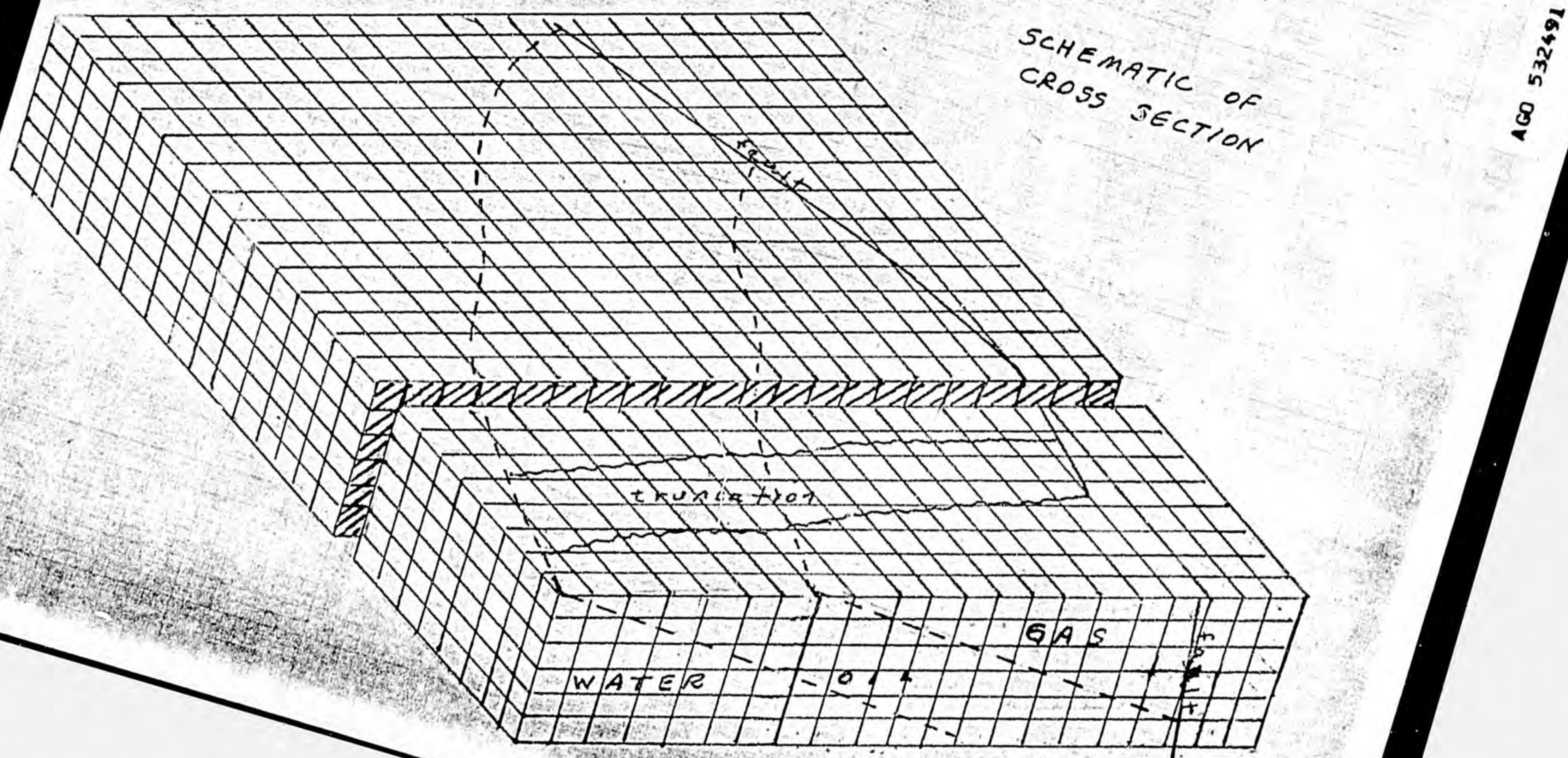
AGO 532489



AGO 532490

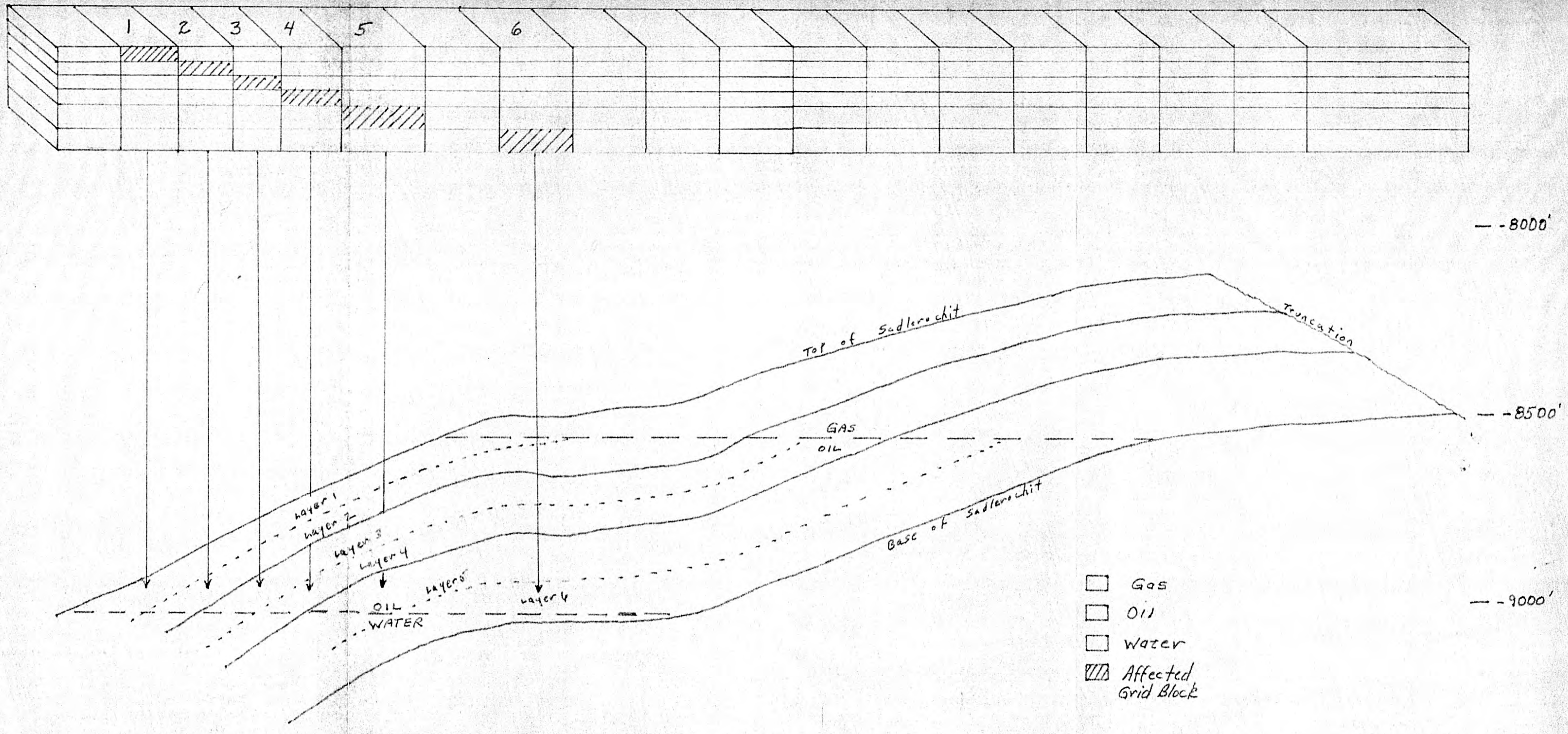


SCHEMATIC OF CROSS SECTION



SCHEMATIC OF 3-D MODEL

SCHEMATIC OF WATER INJECTION BY GRID BLOCK



AGO 532492 L

AGO 532492