

SCOMM

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HOUSE RESOURCES COMMITTEE MEETING
ON
PRUDHOE BAY RESERVOIR MANAGEMENT

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AGO 532113

1 August 6, 1979

2 3:00 p.m.

3
4 BY: MR. MILES

5 I will call the House Resources Committee to order.

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

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

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

17 BY: MR. HAMILTON

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

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1 Attorney General's Office who is the legal advisor for the
2 Commission. And to start this off, you asked for some type
3 of an overview of what a reservoir more or less was and
4 I prepared a little brief presentation I would like to go
5 through and, following that, I have -- we have a presen-
6 tation that Mr. Green will give which will bring you up to
7 date on the -- a brief history and what we have done so
8 far; our past studies and so forth with the reservoir,
9 followed by what we have done with cross-sectional work
10 to date and some pressure maintenance concepts followed by
11 some of our computer analysis work and then Mr. van Poollen
12 will follow that up with a presentation on some of the
13 3-D modeling work that we are doing. You can ask questions
14 at any time during our presentation and we'll..... That's
15 our brief introduction and I'd like to go to the first
16 slide, if you would, Harry, and we'll start off with the.....
17 (Slide show commences.) This, I think most of you are
18 aware of. This slide indicates how the formation of oil
19 in the ground..... You have sediments that have been de-
20 posited in the ground and they're compressed and move down
21 in the lower parts of the earth where the temperature
22 gets extremely high and eventually it's converted to oil
23 over millions of years, and this shows you the very beginning.
24 One thing this points out that -- why you find oil in
25 sedimentary rocks because that's the origin of the oil,

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

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

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

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

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

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

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

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

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1 similar type of mechanism for dissolved gas drive.

2 BY: MR. MILES

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

6 BY: MR. HAMILTON

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

10 UNIDENTIFIED SPEAKER:

11 The water has a head on it?

12 BY: MR. HAMILTON

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

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

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1 field. Mr. Chairman, you mentioned earlier just how
2 large and complex that reservoir is. Just for the enlighten-
3 ment of everyone here and some people that might not be
4 aware, the productive area of the Prudhoe Bay field covers
5 roughly seven townships, and if you're not familiar with
6 the size of a township, you could reduce that to square
7 miles and that's roughly 250 square miles the field covers,
8 or 160,000 acres, roughly. We're talking about a formation
9 that's -- in that productive area -- that's 450 feet
10 thick, and I've used this illustration before, but I think
11 it's a pretty good one. It's twice the height of the
12 Anchorage Westward Hotel in Anchorage, so you've got some-
13 thing that covers 250 squares miles, is 450 feet thick and
14 it's quite a large reservoir to model. In order to attempt
15 this, we've gone to a 3-D model that contains approximately
16 7600 grids or cells, if you might want to call them that.
17 It's a mathematical model and each one of these cells more
18 or less would represent a cubic city block or something of
19 that nature. Now, we tried to describe that reservoir,
20 the fluid parameters and everything that has to go into
21 describing that city cubic block, and each one of these
22 7600 grids. These various parameters that we put in there
23 to make this description are -- 23 or so that are used
24 for each one of these cells. Once you get your model put
25 together and all these parameters described in each one

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

12 BY: MR. MILES

13 Thank you very much, Mr. Hamilton. Really a good presenta-
14 tion. Mr. Chatterton?

15 BY: MR. CHATTERTON

16 Thank you, Mr. Chairman. Commissioner Hamilton, you mentioned
17 the 250 square miles. That's like you're up in the
18 satellite looking down on it with the plan view and the
19 450 feet thickness. Now, first of all, talking about the
20 aerial extent, the plan view, you gave some slides there
21 that showed these sand grains and everything and you spoke
22 of porosity and you spoke of permeability. Now, do you
23 find that the petrophysics say, in one corner of this
24 250 square miles is the same as it is in the opposite
25 corner or what happens? Is it all the same or.....

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1 BY: MR. HAMILTON

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

10 BY: MR. CHATTERTON

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

13 BY: MR. HAMILTON

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

17 BY: MR. CHATTERTON

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

22 BY: MR. HAMILTON

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

24 BY: MR. CHATTERTON

25 And nature makes it different, is that right?

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1 BY: MR. HAMILTON

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

6 BY: MR. CHATTERTON

7 Thank you. Thank you, Mr. Chairman.

8 BY: MR. MILES

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

10 BY: MR. HAMILTON

11 There is no particular requirement. It's just whenever you
12 feel that you can get a -- or you need some more material,
13 and, normally, they just core the vertical holes, and like
14 the first well drilled in Prudhoe on a pad, either the
15 first or the second, or one of the first wells, there's usually
16 a vertical hole, and many of those vertical holes have
17 been cored, and the reason they core the vertical ones,
18 you have a better control over your depth where the sample
19 came from and you're penetrating the formation vertically
20 and not at an angle so you get a better sampling of the for-
21 mation, but I think we have somewhere in the neighborhood
22 of -- I'm off the top of my head -- something like
23 11,000 feet of core from the reservoir itself that's been
24 taken up there in Prudhoe Bay.

25 BY: MR. MILES

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1 When you say 11,000 feet of core, what does that refer to?
2 I guess I don't know what..... What's the dimension of
3 a core? It's four or five inches across?
4 BY: MR. HAMILTON
5 Say the zone is 400 and some odd feet thick. That's
6 equivalent to coring that 400 feet many many times in
7 different portions of the reservoir. You take this five
8 or six inch diameter core through that portion of the
9 reservoir and pull it up to the surface and analyze and,
10 as I say, we've got about 11,000 vertical feet or so of
11 those cores that have been taken from the wells.
12 BY: MR. MILES
13 Thank you. Mr. Hayes?
14 BY: MR. HAYES
15 Yes, Mr. Hamilton, I failed to write down how many cells or
16 grids you said -- you take this 200 plus square miles and
17 you break it up into grids from which you prepare a computer
18 model?
19 BY: MR. HAMILTON
20 Right. That's right.
21 BY: MR. HAYES
22 How many grids was that, roughly?
23 BY: MR. HAMILTON
24 Well, Dr. van Poolen is going to talk on that. I used a
25 rough number of about 7600, now.

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1 BY: MR. HAYES

2 7600.....

3 BY: MR. HAMILTON

4 Grids. Now, is that.....

5 BY: DR. VAN POOLLEN

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

8 BY: MR. HAYES

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

14 BY: MR. HAMILTON

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

22 BY: MR. HAYES

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

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1 BY: MR. HAMILTON

2 Yes, that's true.

3 BY: MR. HAYES

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

11 BY: MR. HAMILTON

12 Um-hum.

13 BY: MR. HAYES

14 Is that what we're talking about?

15 BY: MR. HAMILTON

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

21 BY: MR. HAYES

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

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1 BY: MR. HAMILTON

2 That's right.

3 BY: MR. HAYES

4 And are you getting together and checking results?

5 BY: MR. HAMILTON

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

10 BY: MR. HAYES

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

13 BY: MR. HAMILTON

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

17 BY: MR. HAYES

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

20 BY: MR. HAMILTON

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

24 BY: MR. MILES

25 Joe?

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1 BY: MR. GREEN

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

16 BY: MR. MILES

17 Limited.....

18 BY: MR. GREEN

19 Limited to the amounts that were given in the studies.

20 BY: MR. MILES

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

22 BY: MR. GREEN

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

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

3 BY: MR. MILES

4 Excuse me, Mr. Green. Mr. Chatterton?

5 BY: MR. CHATTERTON

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

10 BY: MR. GREEN

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

22 BY: MR. CHATTERTON

23 Thank you. Thank you, Mr. Chairman.

24 BY: MR. GREEN

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

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

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1 with the testimony that was given by the operators, a con-
2 servation order No. 145 was issued and an inner mortar
3 was given as the operating rules in effectively a two-year
4 basis. It was thought at that time, after a two-year pro-
5 duction history, more data would be gained and hopefully
6 a three-dimensional study would be completed, and at that
7 time there would be a review to see if those orders still
8 stood or there should be a revision. Suffice it to say that
9 there were 15 special field rules for Prudhoe of which eight
10 of them.....

11 BY: MR. MILES

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

14 BY: MR. GREEN

15 Yes.

16 BY: MR. MILES

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

19 BY: MR. GREEN

20 What is the what?

21 BY: MR. MILES

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

25 BY: MR. GREEN

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

7 BY: MR. MILES

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

9 BY: MR. GREEN

10 Yes.

11 BY: MR. MILES

12 Until Dr. van Poolien's work is completed.

13 BY: MR. GREEN

14 Yes.

15 BY: MR. HAMILTON

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

21 BY: MR. MILES

22 Mr. Rogers?

23 BY: Mr. Rogers

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

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1 BY: MR. GREEN

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

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

15 BY: MR. MILES

16 Mr. Chatterton?

17 BY: MR. CHATTERTON

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

25 BY: MR. GREEN

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

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

7 BY: MR. CHATTERTON

8 Thank you. Thank you, Mr. Chairman.

9 BY: MR. MILES

10 The question of water flooding is obviously one that we are
11 going to be discussing at great length. Does the Conserva-
12 tion Commission have the authority to mandate water flooding
13 in the field?

14 BY: MR. GREEN

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

17 BY: MR. MILES

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

20 BY: MR. GREEN

21 Yes.

22 BY: MR. MILES

23 I see. Mr. Hayes?

24 BY: MR. HAYES

25 Mr. Green, did your preliminary studies show greater ultimate

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

3 BY: MR. GREEN

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

10 BY: MR. HAYES

11 Did you say what range you.....

12 BY: MR. GREEN

13 The prior study was between 1.2 and I believe 1.8.

14 BY: MR. HAYES

15 Between 1.2 and 1.8?

16 BY: MR. GREEN

17 Yes.

18 BY: MR. MILES

19 Mr. Chatterton?

20 BY: MR. CHATTER

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

25 BY: MR. GREEN

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

4 BY: MR. HAMILTON

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

16 BY: MR. MILES

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

20 BY: MR. HAMILTON

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

23 BY: MR. MILES

24 Depending on the factors that you plugged in.

25 BY: MR. HAMILTON

Right.

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1 BY: MR. MILES

2 I see.

3 BY: MR. HAMILTON

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

13 BY: MR. MILES

14 Mr. Malone?

15 BY: MR. MALONE

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

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

3 BY: MR. HAMILTON

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

13 BY: DR. VAN POOLLEN

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

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

17 BY: MR. MALONE

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

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1 later on.

2 BY: MR. GREEN

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

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

8 BY: MR. MILES

9 Mr. Chatterton?

10 BY: MR. CHATTERTON

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

14 BY: MR. GREEN

15 That's right.

16 BY: DR. VAN POOLLEN

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

18 BY: MR. CHATTERTON

19 That's not right.

20 BY: DR. VAN POOLLEN

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

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

3 BY: MR. CHATTERTON

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

6 BY: MR. HAMILTON

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

18 BY: MR. GREEN

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

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1 BY: MR. CHATTERTON

2 Thank you. Thank you, Mr. Chairman.

3 BY: MR. GREEN

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

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

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

14 BY: MR. MILES

15 How much is slightly higher?

16 BY: MR. GREEN

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

20 BY: MR. MILES

21 Mr. Chatterton?

22 BY: MR. CHATTERTON

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

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

8 BY: MR. MILES

9 What does that mean?

10 BY: MR. GREEN

11 I think maybe we have something here that might help.

12 BY: MR. MILES

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

15 BY: MR. CHATTERTON

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

19 BY: MR. GREEN

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

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

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

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

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

9 BY: MR. MILES

10 Mr. Chatterton?

11 BY: MR. CHATTERTON

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

13 BY: MR. MILES

14 I presume it was an excellent question.

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

18 BY: MR. GREEN

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

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

15 BY: MR. MILES

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

18 BY: MR. GREEN

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

25 BY: MR. MILES

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1 Of the entire reservoir?

2 BY: MR. GREEN

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

18 BY: MR. MILES

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

22 BY: MR. GREEN

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

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

13 BY: MR. MILES

14 That's what some people have called this Committee.

15 BY: MR. GREEN

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

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

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

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

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

4 BY: MR. MILES

5 When you say we, who are you talking about?

6 BY: MR. GREEN

7 The Conservation Commission and van Poolen.

8 BY: MR. MILES

9 And through van Poolen, so to speak?

10 BY: MR. GREEN

11 Yes.

12 BY: MR. MILES

13 Has the industry made similar tests?

14 BY: MR. GREEN

15 Oh, yes.

16 BY: MR. MILES

17 And how did you interact with them? Do you get that informa-
18 tion or some of it or none of it or all of it or.....

19 BY: MR. GREEN

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

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

7 BY: MR. MILES

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

10 BY: MR. GREEN

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

16 BY: MR. MILES

17 That's good to hear. Mr. Parr?

18 BY: MR. PARR

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

24 BY: MR. GREEN

25 That's correct.

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1 BY: MR. PARR

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

7 BY: MR. GREEN

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

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

4 BY: MR. MILES

5 Mr. Parr?

6 BY: MR. PARR

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

11 BY: MR. GREEN

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

15 BY: MR. PARR

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

18 BY: MR. GREEN

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

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1 might consider about having the dual injector, so

2 BY: MR. PARR

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

6 BY: MR. GREEN

7 Um-hum.

8 BY: MR. PARR

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

14 BY: MR. GREEN

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

20 BY: MR. MILES

21 Mr. Hayes?

22 BY: MR. HAYES

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

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

6 BY: MR. GREEN

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

15 BY: MR. HAYES

16 I could follow up on that. You're probably familiar with
17 a letter I recently wrote to Mr. Hamlin asking him about
18 what I thought was a discrepancy, or at least something that
19 raised a question about a 65 percent recovery factor that
20 was in one of the federal documents that -- based on some
21 testimony or supplemental transmittals were made and then
22 the 40 percent industry statement and I raised the question
23 about which was which. When were you first aware of the
24 65 percent figure or how long ago have you been aware of that?

25 BY: MR. GREEN

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1 As a recovery figure for a gas-invaded gravity drainage
2 reservoir?
3 BY: MR. HAYES
4 Well, for whatever.
5 BY: MR. GREEN
6 Or specifically at Prudhoe?
7 BY: MR. HAYES
8 At Prudhoe. I mean, when were you first aware of that
9 65 percent figure in the publication 95-73? How long ago?
10 BY: MR. GREEN
11 Oh, probably a month or six weeks ago.
12 BY: MR. HAYES
13 Okay, which is, I presume, why Mr. Schmedley (ph) in a recent
14 letter to you was pointing out to you what that meant.
15 BY: MR. GREEN
16 Yes, well, the reason I asked Larry to write the letter was
17 that, by looking at the information on the page that the
18 graph that you are referring to or the table was shown,
19 it doesn't designate that that's just for a limited portion
20 of the reservoir. You could take that as the entire reservoir.
21 BY: MR. HAYES
22 That's the way I took it. That's why I asked that question.
23 BY: MR. GREEN
24 Yes, and so I asked him, all right, since that was an Exxon
25 statement, would he issue a statement corroborating what most

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

3 BY: MR. MILES

4 What portion?

5 BY: MR. GREEN

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

15 BY: MR. HAYES

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

18 BY: MR. GREEN

19 Oh yes.

20 BY: MR. HAYES

21 And I presume.....

22 BY: MR. GREEN

23 Yes, gravity drainage is not uncommon.

24 BY: MR. HAYES

25 Yes.

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AGO 532173

1 BY: MR. GREEN

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

5 BY: MR. HAYES

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

10 BY: MR. GREEN

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

21 BY: MR. HAMILTON

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

24 BY: MR. GREEN

25 No, not yet.

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1 BY: MR. HAMILTON

2 I mailed it the day following our -- the letter I received
3 from you, but we'll find the same thing true in our model.
4 There'll be areas of the reservoir, you're going to have a
5 higher recovery in other areas. In order to get a, say a 35
6 percent recovery or 40 percent overall recovery, you're going
7 to have areas with 60 percent recovery and some areas with
8 30 percent, some with 20 percent. Over a few pages from
9 where you took that 65 percent recovery, they stated what they
10 felt the overall recovery was -- was 40 percent for the entire
11 field and there was a little misunderstanding there, what the
12 65 represented. But it just represented that portion --
13 just portions of the reservoir.

14 BY: MR. LOWENFEL

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

23 BY: MR. MILES

24 Okay.
25

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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 latitude, 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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1 stopped, but we may do it a little differently. Other than
2 that, I think we've been in extremely close agreement. As I
3 say, the nice thing about it is, we do it our way and then
4 ask them if they agree with it.

5 BY: MR. MALONE

6 (Indisc)

7 BY: MR. GREEN

8 Yes.

9 BY: MR. PARR

10 Mr. Hayes, do you have a question?

11 BY: MR. HAYES

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

24 BY: MR. GREEN

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

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

4 BY: MR. HAYES

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

6 BY: MR. GREEN

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

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

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1 3-D computer model. So, we wanted -- the finer we could get,
2 naturally, you see this -- how this contact is a series of
3 straight lines instead of a nice smooth line. This is the
4 thing you get into. If we could have had a billion cross
5 sections or little grids, we probably would have been closer.
6 It would have taken us several hundred years in order to run
7 that, but, so there's some optimum point. We felt this was
8 somewhere near an optimum point. We have to go from this
9 then to a coarser grid to get it on a three dimensional,
10 because if we had a thousand on this, we would end up with
11 something in the neighborhood of thirty or forty thousand
12 grid blocks with twenty different parameters and we just don't
13 have a computer that will handle that. So we had to make
14 them bigger and rather than take just a short production
15 history again to make the big blocks equal the little blocks,
16 we said, alright, let's run the little blocks out to some-
17 thing. Let's have a -- base run, just so we can have some
18 numbers to try and match to and that's what we did. We ran
19 that up and then we could come along and see what we had to
20 do to the bigger blocks, to make them equal the little blocks
21 and then we felt we could go to the 3-D computer model. Well
22 the problem occurred though that when we did that, there was
23 an awful lot of oil down here that wasn't produced. There
24 was no wells to produce it from. So, inadvertently, the
25 number got out that there was only 21.9 percent recovery

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

23 BY: MR. MILES

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

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1 for the Conservation Committee? Mr. McKinnon.

2 BY: MR. MCKINNON

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

8 BY: MR. GREEN

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

11 BY: MR. HAMILTON

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

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1 BY: MR. MCKINNON

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

5 BY: MR. HAMILTON

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

10 BY: MR. MCKINNON

11 The studies show that the rate of -- that ultimate recover-
12 ability drops as you decrease..ah....

13 BY: MR. HAMILTON

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

15 BY: MR. MCKINNON

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

17 BY: MR. HAMILTON

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

20 BY: MR. MCKINNON

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

22 BY: MR. HAMILTON

23 No, we did not.

24 BY: MR. MCKINNON

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

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1 lower than 1.2?

2 BY: MR. HAMILTON

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

10 BY: MR. GREEN

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

20 BY: MR. MCKINNON

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

24 BY: MR. MILES

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

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

3 BY: MR. GREEN

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

14 BY: MR. MILES

15 Go ahead Joe.

16 BY: MR. MCKINNON

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

21 BY: MR. GREEN

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

25 BY: MR. MCKINNON

How significant a difference between the two rates of production

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

2 BY: MR. GREEN

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

20 BY: MR. McKINNON

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

22 BY: MR. GREEN

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

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

6 BY: MR. HAMILTON:

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

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

7 BY: MR. GREEN

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

20 BY: MR. HAMILTON

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

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1 of air when you cone that air down that straw.

2 BY: MR. MCKINNON

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

4 BY: MR. HAMILTON

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

8 BY: MR. GREEN

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

23 BY: MR. MILES

24 Mr. Chatterton?
25

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1 BY: MR. CHATTERTON

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

13 BY: MR. GREEN

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

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

8 BY: MR. CHATTERTON

9 Thank you. Thank you, Mr. Chairman.

10 BY: MR. MILES

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

14 BY: MR. GREEN

15 Yes, that would help.

16 BY: MR. MILES

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

19 BY: MR. GREEN

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

24 BY: MR. MILES

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

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

5 BY: DR. VAN POOLLEN

6 No problem.

7 BY: MR. MILES

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

10 (OFF RECORD)

11 (ON RECORD)

12 BY: MR. MILES

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

22 BY: MR. HAMILTON

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

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

5 BY: MR. MILES

6 That would be great. That would be super. With that, Dr.
7 van Poolen.

8 BY: DR. VAN POOLLEN

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

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

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

19 BY: MR. MILES

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

23 BY: DR. VAN POOLLEN

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

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1 BY: MR. MILES

2than you would have predicted, but it's -- is it
3 higher or lower than it was when we started and by what
4 different degrees?

5 BY: DR. VAN POOLLEN

6 All right. I'll have to look at my graph to get you the
7 exact number. At this moment, the reservoir pressure is
8 171 pounds lower than it was when we started, so when I say
9 at this moment, that is after a withdrawal of 633 million
10 barrels. That is what I call this moment. I don't have
11 any data beyond that myself that I can make that calculation,
12 so I made the calculation at 633 and right now I believe the
13 total withdrawal is 743 so at 633 million barrels withdrawal
14 we observe a field pressure drop of 171 pounds and the model
15 would have predicted 181 pounds.

16 BY: MR. MILES

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

21 BY: DR. VAN POOLLEN

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

24 BY: MR. MILES

25 Lower, yes, yes.

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1 BY: DR. VAN POOLLEN

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

5 BY: MR. MILES

6 Okay. Thank you.

7 BY: DR. VAN POOLLEN

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

16 BY: MR. MILES

17 Mr. Chatterton?

18 BY: MR. CHATTERTON

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

23 BY: DR. VAN POOLLEN

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

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

10 BY: MR. CHATTERTON

11 Thank you.

12 BY: MR. MILES

13 I think you can please continue, sir.

14 BY: DR. VAN POOLLEN

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

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

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1 today, which is not the full 3-D model as yet, however, the
2 cross sectional work that Joe Green was showing you a graph
3 of is showing us that these shale breaks are not 100% barriers,
4 namely, if we tried to match in that fine grid section, which
5 I believe -- what was it -- a thousand eighty grid points --
6 if we assigned a zero permeability into the shale breaks, we
7 cannot possibly match our pressures in that particular cross
8 section, in that pie cut, in that section of the field. We
9 definitely have to have permeability in it. Now, whether that
10 is, scientifically speaking, that the shale itself leaks or
11 that the shale is discontinuous and has holes in it and some
12 time during this meeting, maybe tomorrow, you will hear the
13 expression windows; I mean, it's just holes in the shale.
14 We definitely feel that these shales must leak and that in
15 itself is a very important part of this study. We're getting
16 a much better and better reservoir description as we are going.
17 To do the 3-D model study, we are talking about computer runs
18 that are costing in the order of, well, between \$5,000 and
19 \$12,000 per run, which is an astronomical number and it's kind
20 of frightening to push the button in the morning and then in
21 the afternoon find out that you have the wrong cart somewhere.
22 It's bad enough if you know it's a true boo-boo. You can kind
23 of write that on experience, but if you stick something in
24 that you didn't -- that you kind of overlooked, then it's
25 kind of criminal, so we are spending a terrific amount of time.

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

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

12 BY: MR. MILES

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

15 BY: DR. VAN POOLLEN

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

25 BY: MR. MILES

Thank you.

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1 BY: DR. VAN POOLLEN

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

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

6 BY: MR. MILES

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

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

9 BY: DR. VAN POOLLEN

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

12 BY: MR. MILES

13 Joe and Hoyle were talking about 7600.

14 BY: DR. VAN POOLLEN

15 Those were totals.

16 BY: MR. MILES

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

19 BY: DR. VAN POOLLEN

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

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1 7600, I'd forget about it. I'd say 4600 active nodes.
2 How many is that there, Joe? I've forgotten by now. I know
3 it's.....
4 BY: MR. GREEN
5 That are active?
6 BY: DR. VAN POOLLEN
7 Well, total, that you have there on that.....
8 BY: MR. GREEN
9 About 7600.
10 BY: DR. VAN POOLLEN
11 Yeah, but I mean how many by how many?
12 BY: MR. GREEN
13 Oh. We're talking 24 by 45.
14 BY: DR. VAN POOLLEN
15 Twenty-four by 45 and then we have six layers in there, but
16 we're not using all of these. We are assigning them as being
17 no flow. There is no porosity in them on the outside of the
18 field. Or in the aquifer, instead of using all of the cells,
19 we have been assigning only a lesser number to represent the
20 aquifer. Instead of just going all the way to the group
21 range, we have stopped short.
22 BY: MR. MILES
23 Thank you, sir.
24 BY: DR. VAN POOLLEN
25 Well, we hear a word floating around and that's when I jumped

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

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

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1 time.

2 BY: MR. MILES

3 Mr. Chatterton?

4 BY: MR. CHATTERTON

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

10 BY: DR. VAN POOLLEN

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

16 BY: MR. CHATTERTON

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

22 BY: DR. VAN POOLLEN

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

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

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

9 BY: MR. CHATTERTON

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

11 BY: MR. GREEN

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

16 BY: DR. VAN POOLLEN

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

23 BY: MR. MILES

24 Two matching runs?

25 BY: DR. VAN POOLLEN

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

14 BY: MR. MILES

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

21 BY: DR. VAN POOLLEN

22 That's correct.

23 BY: MR. MILES

24 Approximately how many runs will you make?

25 BY: DR. VAN POOLLEN

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1 Prediction runs?

2 BY: MR. MILES

3 Yes, sir.

4 BY: DR. VAN POOLLEN

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

9 BY: MR. GREEN

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

14 BY: MR. MILES

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

16 BY: MR. CHATTERTON

17 Yeah, I guess I've got a philosophical question of anybody
18 that might want to answer it. Technically, I presume, and
19 if this in substance is wrong, let me know, that with this
20 3-D model that the State is about to have or now has, and
21 with our present Commission to enforce Title 31, why we're
22 going to be able to make decisions as to the appropriate
23 reservoir management to maximize ultimate recovery. Let's
24 say that, given that, so to speak, -- I guess my question
25 is, is there anything else we should be doing and then

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

6 BY: MR. HAMILTON

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

10 BY: MR. CHATTERTON

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

12 BY: MR. HAMILTON

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

16 BY: MR. CHATTERTON

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

18 BY: DR. VAN POOLEN

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

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

6 BY: MR. MILES

7 Mr. McKinnon?

8 BY: MR. MCKINNON

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

12 BY: DR. VAN POOLLEN

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

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1 BY: MR. McKINNON

2 Will you be looking at different rates of production?

3 BY: DR. VAN POOLLEN

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

8 BY: MR. McKINNON

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

11 BY: MR. HAMILTON

12 Yes, we'll make some runs.

13 BY: DR. VAN POOLLEN

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

19 BY: MR. McKINNON

20 What didn't make any difference, rate production?

21 BY: DR. VAN POOLLEN

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

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

3 BY: MR. MCKINNON

4 What were the two rates you were looking at?

5 BY: DR. VAN POOLLEN

6 The ratios?

7 BY: MR. MCKINNON

8 The two rates.

9 BY: DR. VAN POOLLEN

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

13 BY: MR. MCKINNON

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

16 BY: DR. VAN POOLLEN

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

21 BY: MR. GREEN

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

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1 BY: MR. MCKINNON

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

5 BY: DR. VAN POOLLEN

6 If you are looking at a 25-year line or you're looking at a
7 15 to 25 year line for sensitivity, in general, would be
8 very small. You wouldn't see that much difference. Now,
9 you take a field that you normally, in the normal set of
10 circumstances, could issue 25 years, and you try to rip it
11 out of there in 10 years, yeah, you're going to see some
12 damage, but not the orders of magnitude that we're talking
13 about here. This field is not even developed yet, you know,
14 and we haven't even drilled, I'd say, well, in the order
15 of half the wells have been drilled. The exact number that
16 will be drilled depends on the final budget that people have,
17 you know, but, I mean, we're still in a very active drilling
18 situation and.....

19 BY: MR. MCKINNON

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

23 BY: DR. VAN POOLLEN

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

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1 that's a good guess I have, but I think that it's going to be
2 22 and I compare two thoughts. I mean, then I am not comparing
3 to very precise things. If there's only -- if I'm going
4 from 20 or 22 percent, I'll keep my eyes open for the run with
5 22 as time goes on, but I'm certainly not going to initiate
6 that today if that has dangers involved, and you certainly
7 aren't going to learn anything from this field if you're
8 not going to produce any of it. You've got to produce at a
9 certain rate and you've got to get some reservoir response.
10 Here we've been at it for in the order of, let's say, 10
11 percent of the recoverable oil in that order, is what we're
12 talking. You know, we only have 171 pound pressure drop.
13 Luckily, we know all of this because we have so many measure-
14 ments, but.....

15 UNIDENTIFIED SPEAKER

16 (Inaudible)

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

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

18 BY: MR. MILES

19 Mr. Parr?

20 BY: MR. PARR

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

25 BY: DR. VAN POOLLEN

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

9 BY: MR. PARR

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

22 BY: DR. VAN POOLLEN

23 Yes.

24 BY: MR. PARR

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

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

4 BY: DR. VAN POOLLEN

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

12 BY: MR. PARR

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

16 BY: DR. VAN POOLLEN

17 No, there's not a unique value.

18 BY: MR. PARR

19 It depends on the characteristics of the individual reservoir?

20 BY: DR. VAN POOLLEN

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

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

11 BY: MR. PARR

12 Thank you.

13 BY: MR. MILES

14 Mr. Malone?

15 BY: MR. MALONE

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

23 BY: DR. VAN POOLLEN

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

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

6 BY: MR. MALONE

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

10 BY: DR. VAN POOLLEN

11 That's correct.

12 BY: MR. MALONE

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

16 BY: DR. VAN POOLLEN

17 Five years -- at five years.

18 BY: MR. MALONE

19 That would be what--1982? Would the -- what would be
20 the runs done on that to show what effect gas production
21 in later years, like in 1983, or as more likely the case,
22 1985 or later, say, comparison made then as to how that might
23 effect ultimate recovery of oil and gas from Prudhoe?

24 BY: DR. VAN POOLLEN

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

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AGO 532224

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

7 BY: DR. DOSCHER

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

10 BY: MR. MILES

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

13 BY: DR. VAN POOLLEN

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

18 BY: MR. CHATTERTON

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

21 BY: MR. MILES

22 There's a gas sales at seven.

23 BY: MR. CHATTERTON

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

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1 your January, 1976 report.

2 BY: MR. MALONE

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

11 BY: DR. DOSCHER

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

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

10 BY: MR. MILES

11 Mr. Malone?

12 BY: MR. MALONE

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

24 BY: MR. HAMILTON

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

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

16 BY: MR. MILES

17 Mr. Malone?

18 BY: MR. MALONE

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

23 BY: MR. MILES

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

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1 came up, to give us a call.

2 BY: MR. MALONE

3 May I continue?

4 BY: MR. MILES

5 Mr. Malone?

6 BY: MR. MALONE

7 Thank you. How do you take economics into account?

8 BY: MR. HAMILTON

9 We look at what we think might be an economic limit termination
10 rate for the field. Right now, it's kind of a wild guess.

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

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1 That's his course of action he can take.

2 BY: MR. MALONE

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

17 BY: MR. HAMILTON

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

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

5 BY: MR. LOWENFEL

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

16 BY: MR. MALONE

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

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1 BY: MR. HAMILTON
2 Well, we can look at spacing, if that's what you're driving
3 at, but we can't.....
4 BY: MR. MALONE
5 Well, not the spacing, but the -- what I'm really talking
6 about is the.....
7 BY: MR. HAMILTON
8 Per well rate?
9 BY: MR. MALONE
10 The amount of money that's invested versus the ultimate recovery.
11 Presumably, if you wanted to spend enough money, you could
12 probably get 90 percent of the oil out but it would be long
13 past any economic return.
14 BY: MR. HAMILTON
15 Yes, you could mine the oil and get it all out, but we have
16 to live within the constraints of known technology, and we
17 can't tell -- force the operator to do something that's completel
18 ridiculous. We just have to live within what they can do under
19 the present scheme of technology.
20 BY: MR. MALONE
21 As far as the technology goes, what I was asking is how the
22 Commission evaluates, I guess, the economic life of the field
23 under -- to make that determination.
24 BY: MR. HAMILTON
25 I don't know what else I can tell you other than how we calculate

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

4 BY: MR. MALONE

5 Maximize the total recovery from the field?

6 BY: MR. HAMILTON

7 Yes.

8 BY: MR. GREEN

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

15 BY: MR. MALONE

16 Um-hum.

17 BY: MR. GREEN

18 Yes, that could be an order that came in.

19 BY: MR. LOWENFEL

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

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

16 BY: MR. MILES

17 Mr. Malone?

18 BY: MR. MALONE

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

23 BY: MR. HAMILTON

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

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

6 BY: MR. MALONE

7 Have you encountered any such circumstances?

8 BY: MR. HAMILTON

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

15 BY: MR. MALONE

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

23 BY: MR. HAMILTON

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

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

8 BY: MR. MALONE

9 Is that the situation with the gas flare?

10 BY: MR. HAMILTON

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

13 BY: MR. MALONE

14 Thank you, Mr. Chairman.

15 BY: MR. MILES

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

21 BY: DR. VAN POOLLEN

22 Correct.

23 BY: MR. MILES

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

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

6 BY: MR. HAMILTON

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

9 BY: MR. MILES

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

11 BY: MR. HAMILTON

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

23 BY: MR. MILES

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

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1 BY: DR. VAN POOLLEN

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

4 BY: MR. GREEN

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

8 BY: MR. MILES

9 What does it generally indicate in other fields?

10 BY: MR. GREEN

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

15 BY: DR. VAN POOLLEN

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

17 BY: MR. GREEN

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

22 BY: DR. VAN POOLLEN

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

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

6 BY: MR. MILES

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

9 BY: DR. VAN POOLLEN

10 '76 -- January of '76 report.

11 BY: MR. MILES

12 Mr. Chatterton?

13 BY: MR. CHATTERTON

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

20 BY: MR. GREEN

21 Used 85%, I think.

22 BY: DR. VAN POOLLEN

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

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1 so we never had a full exposure anywhere.

2 BY: MR. CHATTERTON

3 All right, fine, but did we visualize that -- well, we
4 had the standoff, as you say, from the gas and the water.

5 Did we also take into account that maintaining that standoff
6 we were withdrawing from different lithologic units within
7 the 440 feet of oil column?

8 BY: DR. VAN POOLLEN

9 Yes, we were withdrawing from different units.

10 BY: MR. CHATTERTON

11 And in the model even?

12 BY: DR. VAN POOLLEN

13 Yes.

14 BY: MR. CHATTERTON

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

16 BY: DR. VAN POOLLEN

17 And we have it in the 3-D now.

18 BY: MR. CHATTERTON

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

20 BY: MR. MILES

21 Mr. Hayes?

22 BY: MR. HAYES

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

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1 gravity drained -- that's under gravity drain?

2 BY: DR. VAN POOLLEN

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

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

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

9 BY: MR. MILES

10 Doctor, just a moment. Mr. McKinnon?

11 BY: MR. MCKINNON

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

15 BY: DR. VAN POOLLEN

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

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

3 BY: MR. MILES

4 Right away?

5 BY: DR. VAN POOLLEN

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

10 BY: MR. MCKINNON

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

13 BY: MR. HAMILTON

14 When we reviewed this plan before, we encouraged the operators
15 to start putting water in the ground as soon as they had
16 enough available water in the field there and that rate at
17 that time was determining about 100,000 barrels a day and,
18 looking at our prediction at that time before the field
19 started, it looked like they'd reach that volume in two years
20 and they'd start putting the produced water away. Well, it
21 turns out the water has not moved in as fast as we anticipated.
22 It's up around 20,000 barrels a day now and we anticipated in
23 81 -- that it should be somewhere around 100,000 barrels
24 a day and it will be returned to the reservoir. Now, they
25 are running injectivity tests now to try to find out where

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

4 BY: MR. MCKINNON

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

6 BY: MR. HAMILTON

7 '81, yes, would be the earliest.

8 BY: MR. MILES

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

12 BY: DR. VAN POOLLEN

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

21 BY: MR. MILES

22 A pilot -- pilot.

23 BY: DR. VAN POOLLEN

24 That's correct.

25 BY: MR. MCKINNON

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1 Why not pump it out of the ocean?

2 BY: DR. VAN POOLLEN

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

10 (PORTION MISSING DUE TO CHANGE OF TAPE)

11 BY: MR. HAMILTON

12 we'll have enough produced water to return to the reser-
13 voir. Now, as far as using the seawater, they have filed for
14 permits to obtain water from the ocean to use in their full-
15 scale water-injection program. And they've also filed for
16 permits to obtain approval for all their gas turbines and so
17 forth needed to power all this injection equipment. And this
18 comes under the EPA air pollution requirements that they have
19 to meet. And when they get those permits, it's my understand-
20 ing they'll order the equipment for the large-scale water-
21 injection.

22 BY: MR. MCKINNON

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

25 BY: MR. HAMILTON

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

6 BY: MR. MCKINNON

7 Do the companies believe that water injection's going to in-
8 crease their recoverability?

9 BY: MR. HAMILTON

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

15 BY: MR. MILES

16 Mr. Chatterton?

17 BY: MR. CHATTERTON

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

21 BY: MR. HAMILTON

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

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

14 BY: MR. CHATTERTON

15 Thank you. Thank you, Mr. Chairman.

16 BY: MR. MILES

17 Mr. Hayes?

18 BY: MR. HAYES

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

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

3 BY: MR. HAMILTON

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

11 BY: MR. HAYES

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

15 BY: MR. HAMILTON

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

22 BY: MR. HAYES

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

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1 BY: MR. HAMILTON

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

7 BY: MR. KUGLER

8 We're getting sea water (indisc.)

9 BY: MR. HAMILTON

10 No.

11 BY: DR. VAN POOLLEN

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

16 BY: MR. KUGLER

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

22 BY: MR. LOWENFEL

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

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1 BY: MR. MILES

2 Please continue, Dr. van Poolen.

3 BY: DR. VAN POOLLEN

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

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

19 BY: MR. DOSCHER

20 Go right ahead.

21 BY: DR. VAN POOLLEN

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

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

21 BY: MR. ZHAROFF

22 Excuse me, Doctor. Mr. Chatterton?

23 BY: MR. CHATTERTON

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

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1 BY: MR. ZHAROFF

2 Okay.

3 BY: DR. VAN POOLLEN

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

15 BY: MR. ZHAROFF

16 Mr. Chatterton?

17 BY: MR. CHATTERTON

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

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1 might be -- that you do come up with and find -- might
2 be compatible with and only with gas injection?
3 BY: DR. VAN POOLLEN
4 I'm not sure I follow your question. I presume it's directed
5 at me and not Todd.
6 BY: MR. CHATTERTON
7 It is and let me elucidate on it. I'm saying, basically,
8 why, when you go into research, you don't know what your
9 answer is going to be.
10 BY: DR. VAN POOLLEN
11 Correct.
12 BY: MR. CHATTERTON
13 (Indisc.) Okay. We had a horrendous
14 gas cap there. That's obvious. We had a lot of solution
15 gas. That's obvious. Okay, now, maybe in your research,
16 you find an enhanced recovery mechanism. You mentioned CO2
17 for example and the swelling that it will cause. Doesn't
18 it seem appropriate -- and my question is, speak to the
19 prudence of keeping all options open for a potential such
20 as that by keeping your gas cap present.
21 BY: DR. VAN POOLLEN
22 Now, I see what you're driving at. What you're saying is,
23 it would be prudent not to produce any gas because you might
24 need it.
25 BY: MR. CHATTERTON

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1 Roger.

2 BY: DR. VAN POOLLEN

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

6 BY: MR. CHATTERTON

7 I knew I wouldn't like the answer.

8 BY: DR. VAN POOLLEN

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

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

7 BY: MR. CHATTERTON

8 Thank you. Thank you, Mr. Chairman.

9 BY: DR. VAN POOLLEN

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

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

21 BY: MR. MILES

22 A lot of other people thought so (indisc. - simultaneous con-
23 versation).

24 BY: DR. VAN POOLLEN

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

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

9 BY: MR. MILES

10 Representative Hayes.

11 BY: MR. HAYES

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

14 BY: DR. VAN POOLLEN

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

17 BY: MR. HAYES

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

21 BY: MR. MILES

22 Yes, that's right.

23 BY: MR. HAYES

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

25 BY: DR. VAN PCOLLEN

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

6 BY: DR. DOSCHER

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

10 BY: MR. MILES

11 Mr. Parr.

12 BY: MR. PARR

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

18 BY: MR. HAMILTON

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

21 (Various members of the audience offer percentages.)

22 BY: MR. HAMILTON

23 About 20% of the recoverable oil, sir.

24 BY: MR. CHATTERTON

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

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1 eous conversation).
2 (Conversation in background regarding percentages.)
3 BY: MR. HAMILTON
4 Okay.. 15 to 16. Our computer-minded man
5 BY: MR. MILES
6 Mr. Chatterton.
7 BY: MR. CHATTERTON
8 Yeah. One real general question. I gather that water flood-
9 ing was pretty much in its infancy in the early 40's, and it
10 has become a very well-accepted secondary recovery method.
11 Since the early 40's, or whenever its conception was -- that
12 order of magnitude -- how many fields do you believe was
13 water flooding ever commenced as early in the productive life
14 of that field as is being proposed here?
15 BY: DR. VAN POOLLEN
16 Very few.
17 BY: MR. CHATTERTON
18 Do you think there's any?
19 BY: MR. GREEN
20 One I can think of. An extension of Wilmington. But, in
21 that situation, they knew exactly what they were getting into.
22 It was merely an extension of an existing field. And the
23 ironic thing about that, the area of the reservoir that was --
24 water flooding was instituted initially, and that was primarily
25 to avoid subsidence. For those of you who are familiar with

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

6 BY: DR. DOSCHER

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

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7 ON
8 PRUDHOE BAY RESERVOIR MANAGEMENT
9

10 ROOM 118 - CAPITOL BUILDING
11 JUNEAU, ALASKA
12

13 August 6 and 7, 1979
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1 a much smaller gas cap. It still has gas caps. And there
2 are many fields in Alberta which, although they were not
3 flooded from day one, do get the instructions that water
4 flooding will be very early. So, in general, in modern times
5 if there is no natural water flood drive and the field is
6 being managed well, plans for a water flood will come in very
7 early, only pending the resolution of the drilling patterns
8 and things of that sort. That's the best of my knowledge.

9 BY: MR. GREEN

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

16 BY: DR. DOSCHER

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

21 BY: MR. GREEN

22 He does. (Laughter)

23 BY: DR. VAN POOLLEN

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

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

25 BY: MR. KRUGER

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

3 BY: MR. MILES

4 If it happens that the pressure in the field drops substan-
5 tially, or we find that perhaps water flooding has started
6 too late, is that irreparable to overall maximum recovery?

7 BY: DR. VAN POOLLEN

8 Within reason, there is no great concern.

9 BY: MR. MILES

10 Thank you.

11 BY: DR. DOSCHER

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

13 BY: MR. MILES

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

16 BY: DR. VAN POOLLEN

17 Members of the Commission, thank you very much.

18 BY: MR. MILES

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

21

22

23

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25

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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,

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

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

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

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

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

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1 mitigated by gas coning and shale breaks within the reservoir.
2 We felt that both factors might indeed be far more signifi-
3 cant than that predicted by the particular reservoir
4 description developed by the operators. Our experience did
5 not indicate to us that the properties of the Prudhoe Bay
6 reservoir would permit such a high recovery to be reached by
7 the proposed operating plan. We noted to the legislature
8 that information we had access to suggested that high re-
9 coveries of this kind, and this is indeed a high recovery
10 without secondary operations, was usually confined to
11 reservoirs which had significantly more favorable charac-
12 teristics than those of Prudhoe Bay, particularly the
13 permeability, the pore size distribution of the reservoir.
14 We had also significant evidence that if unaided gravity
15 drainage would be affected, unaided that is by no further
16 gas injection, if that were true then recovery efficiency
17 would still be higher if you maintained pressure while the
18 gravity segregation took place. Now in information which
19 Exxon presented to the United States Congress, they give a
20 list of six reservoirs which apparently gave rather unequivocal
21 support for our position. They cited this list of six
22 reservoirs and said that in these gravity drainage reservoirs
23 the recovery was between 47 and 87%, but what Exxon did not
24 specifically reveal is that these six reservoirs were sub-
25 jected to gas injection and in each one of these reservoirs

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1 for which data has been obtained, the oil mobility is signi-
2 ficantly greater than that in Prudhoe Bay. By....
3 BY: MR. MILES
4 If I could interrupt.
5 BY: DR. DOSCHER
6 Um hum, anytime.
7 BY: MR. MILES
8 Subjected the gas injection, for what period of time, is
9 there an average period of time?
10 BY: DR. DOSCHER
11 I'd have to look up the data but all of them were finished up
12 by gas injection.
13 BY: MR. MILES
14 I see, and that...does that preclude gas...any gas sales at
15 all to your knowledge.
16 BY: DR. DOSCHER
17 No, no, no this is...now, I'm talking about these six.
18 reservoirs out here.
19 BY: MR. MILES
20 Right.
21 BY: DR. DOSCHER
22 Okay, I don't even know where they got the gas, whether they
23 got the gas from the same reservoir or from someplace else.
24 But what I am speaking to here is that, in these six
25 reservoirs for which the recovery efficiency was so high,

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1 gas was reinjected to maximize the gravity drainage.

2 BY: MR. MILES

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

5 BY: DR. DOSCHER

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

14 BY: MR. MILES

15 Thank you sir.

16 BY: DR. DOSCHER

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

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

18 BY: MR. MILES

19 What does that mean?

20 BY: DR. DOSCHER

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

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1 BY: MR. MILES

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

3 BY: DR. DOSCHER

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

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

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

11 BY: MR. MILES

12 I'm getting confused.

13 BY: DR. DOSCHER

14 Okay.

15 BY: MR. MILES

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

19 BY: DR. DOSCHER

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

21 BY: MR. MILES

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

24 BY: DR. DOSCHER

25 No, no. Water injection for pressure maintenance means putting

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1 the water early before the pressure has substantially de-
2 clined.
3 BY: MR. MILES
4 Okay, where does this water come from?
5 BY: DR. DOSCHER
6 Oh, it can come from any place.
7 BY: MR. MILES
8 Probably source water.
9 BY: DR. DOSCHER
10 Oh, it's a source water, yes, it comes from the rain, it can
11 come from the sea, it can come from any place you can lay
12 your hands on it. Okay? But water flooding, it's a fine
13 point here, water flooding refers to, you've let the
14 pressure decline then you put the water in to flood the oil
15 out.
16 BY: MR. MILES:
17 So, water flooding is essentially a catch-up..ah..water
18 injection, the way you explain it, is a preventative.
19 BY: DR. DOSCHER
20 Right. Exactly. One would call it, the first one pressure
21 maintenance by water injection and the other is water flooding.
22 BY: MR. MILES:
23 I see. To bring the pressure up to....
24 BY: DR. DOSCHER
25and bring the pressure up.

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1 BY: MR. MILES

2 Thank you.

3 BY: DR. DOSCHER

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

21 BY: MR. MILES

22 Well, what's water invasion?

23 BY: DR. DOSCHER

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

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1 natural water drive.

2 BY: MR. MILES

3 Okay.

4 BY: DR. DOSCHER

5 The East Texas field is probably the greatest example of this.
6 It has a natural slow water influx, production has been
7 managed by the State because of competitive influences since
8 the early 30's and the recovery efficiency there is going to
9 be over 80%. Now, that's a very special field, don't...I'm
10 not trying to tell you that all water floods are going to be
11 80%. But, natural water invasion in a good reservoir gives
12 you these high recoveries. Cores taken from behind the water
13 invaded region in East Texas give oil residuals as low as 4
14 and 5%. The oil is substantially swept out. All along the
15 south...Louisiana and south Texas coast, where we have
16 natural water invasion, we see the same thing. A slow
17 natural water influx is apparently unbeatable. There are
18 some places where you can by restoring gas in very good
19 reservoirs as Exxon has pointed out, yet recoveries that are
20 comfortable. Water flooding, in general, does not require
21 too much piloting as suggested yesterday, in my thinking,
22 because you can't tell very much from a water pilot unless
23 you go in and do it on a fairly large scale or go in and
24 drill an extensive number core holes. The original water
25 pilots, many of which were pioneered by the company I formerly

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

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

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1 I'd like to bring the State's attention to way the Province
2 of Alberta manages its reserves. The Province produced in
3 1977 only a million barrels of crude oil and had a proven
4 reserve of 5.4 billion at the end of that year. The Province
5 is one of the most richest, one of the richest and most
6 solvent political entities in the world. Its oil and gas
7 conservation board maintains its own technical staff which
8 analyzes all new pool discoveries. An operator can be
9 excused from committing a pressure maintenance program only
10 if it is concluded would not recover additional economic
11 reserves. The Province's evaluation of recovery and economics
12 is the initial framework for any discussion on the subject.
13 The Province reports that 3.8 billion barrels of its total
14 reserves have been added by pressure maintenance compared to
15 7.6 realized from natural depletion. The need for this
16 State to have its own appraisal of Prudhoe Bay is obvious
17 and it is very rewarding to see the State going ahead with
18 it. Its unfortunate that the study being undertaken by
19 VanPoolen and Associates is taking somewhat longer than I
20 had originally estimated to this committee. One of the
21 major problems in this study has been the assignment of
22 permeabilities and the positioning of the shale barriers in
23 the model of the reservoir. Both of these parameters are of
24 critical importance in effecting the outcome of the simulation
25 and it is for this reason that VanPoolen and Associates have

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

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

16 BY: MR. PARR

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

19 BY: DR. DOSCHER

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

22 BY: MR. PARR

23 Okay, thank you.

24 BY: DR. DOSCHER

25 We've got another....

BY: MR. PARR

I just wanted to make sure that was deliberately chosen.

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1 BY: MR. MILES

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

3 BY: DR. DOSCHER

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

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1 Anchorage. Now is 150 significant? I think it is, particu-
2 larly if the solution gas ratio is 750, an average of 900,
3 although you say, "Well, it's -- it's only 150, its 20%,"
4 but you don't get up to 900 on the predicted Exxon runs or
5 even on VanPoollen runs, I don't think we can use the old
6 VanPoollen model here as any reference because it was a 2-D
7 Model, so I think the reference has to be to the 3-D runs.
8 You don't get up to 900 for four or five years. Now, the
9 pressure decline, the numbers that were quoted yesterday were
10 six hundred and thirty million -- three million barrels in
11 171 psi. That's .28 psi per million barrels. Again, looking
12 at the xerox copies of the Exxon report and there has to be
13 some error there, but still looking at all thirteen runs and
14 taking average figures, it seems that it should be closer to
15 two tenths, a difference of about 50%. Now, I think that's --
16 that's something significant because you're in the early life
17 of the reservoir and you have to look at these fine points.
18 I hope I'm wrong, but I'd stop looking at why this difference
19 is being-- occurring.

20 BY: MR. CHATTERTON

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

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1 BY: DR. DOSCHER

2 ...Oh yes, yes...

3 BY: MR. CHATTERTON

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

6 BY: DR. DOSCHER

7 Oh, it varies from 700 to 900.

8 BY: MR. CHATTERTON

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

11 BY: DR. DOSCHER

12 900.

13 BY: MR. CHATTERTON

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

16 BY: DR. DOSCHER

17 I'm comparing to the 750 average that is used in the simula-
18 tion studies and the projections of the field behavior.

19 BY: MR. CHATTERTON

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

23 BY: DR. DOSCHER

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

25 BY: MR. CHATTERTON

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

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1 BY: DR. DOSCHER

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

9 BY: MR. CHATTERTON

10 Thank you.

11 BY: DR. DOSCHER

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

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

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1 calculation before because I knew what it was and didn't
2 think it worth mentioning, but at this time I will mention it
3 that in fifteen years based on the VanPoolen models, and
4 again these are -- you know -- they have to be confirmed by
5 the 3-D, we would have to reinject about 15 trillion cubic
6 feet of gas in 15 years if we did not sell it. It would
7 take one and a half trillion cubic feet as fuel to compress
8 this gas and return it to the reservoir. Now, this one and
9 a half trillion is less than 4% of the total and if you're
10 going to produce gas after that time, this difference of
11 4% is just not going to effect the ultimate recovery of gas
12 from the reservoir. So, the matter of wasting energy or
13 using energy in an irrevocable way to
14 return the gas to the reservoir, I don't believe is a valid
15 point. Another point which we were fairly well criticized
16 for and it wasn't something we said should be done, but we
17 posed the question in our report, should consideration be
18 given to using the crude oil line for the two phase flow of
19 gas and oil at that time some fifteen years away when the
20 oil production might have dropped to five hundred thousand
21 barrels and of course continue to do so, we said, should
22 consideration be given. Well, we heard everything that --
23 from -- that this was a mind-boggling idea and then Exxon
24 subsequently did a very professional job, a good job, of
25 showing that with conventional technology this was -- just

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

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AGO 532293

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

8 BY: MR. MILES

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

11 BY: MR. HAYES

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

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

18 BY: MR. MILES

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

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AGO 532294

1 BY: MR. Hayes

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

5 BY: DR. DOSCHER

6 Oh, I don't think so.

7 BY: MR. MILES

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

10 BY: MR. CHATTERTON

11 I think so too.

12 BY: MR. MILES

13 Mr. Chatterton.

14 BY: MR. CHATTERTON

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

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AGO 532295

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

4 BY: DR. DOSCHER

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

7 BY: MR. CHATTERTON

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

10 BY: DR. DOSCHER

11 Absolutely.

12 BY: MR. CHATTERTON

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

16 BY: DR. DOSCHER

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

18 BY: MR. CHATTERTON

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

22 BY: DR. DOSCHER

23 That's right.

24 BY: MR. CHATTERTON

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

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1 to rate sensitivity?

2 BY: DR. DOSCHER

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

10 BY: MR. CHATTERTON

11 I'm not sure I understand.

12 BY: DR. DOSCHER

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

18 BY: MR. CHATTERTON

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

20 BY: DR. DOSCHER

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

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1 BY: MR. CHATTERTON

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

6 BY: DR. DOSCHER

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

8 BY: MR. CHATTERTON

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

14 BY: DR. DOSCHER

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

21 BY: MR. CHATTERTON

22 I understand.

23 BY: MR. CHATTERON

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

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

3 BY: MR. CHATTERTON

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

6 BY: DR. DOSCHER

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

12 BY: MR. CHATTERTON

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

15 BY: DR. DOSCHER

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

19 BY: MR. CHATTERTON

20 Thank you. Thank you Mr. Chairman.

21 BY: MR. MILES

22 Mr. Rogers.

23 BY: MR. ROGERS

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

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1 percentage of U.S. domestic oil reserves ⁺¹²ⁿ and gas reserves,
2 that we should sort of concentrate, I guess, on ultimate
3 recovery of crude oil, but is the State's interest, do you
4 think, then on the crude oil recovery on the total hydro-
5 carbon recovery.

6 BY: DR. DOSCHER

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

14 BY: MR. ROGERS

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

16 BY: DR. DOSCHER

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

22 BY: MR. MILES

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

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

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

4 BY: DR. DOSCHER

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

11 BY: MR. MILES

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

15 BY: DR. DOSCHER

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

17 BY: MR. MILES

18 Well, okay.

19 BY: DR. DOSCHER

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

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

4 BY: MR. MILES

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

12 BY: DR. DOSCHER

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

17 BY: MR. MILES

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

20 BY: DR. DOSCHER

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

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

3 BY: MR. MILES

4 We in essence have two different ball games.

5 BY: DR. DOSCHER

6 That's right.

7 BY: MR. MILES

8 Thank you. Mr. Chatterton.

9 BY: MR. CHATTERON

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

20 BY: DR. DOSCHER

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

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

4 BY: MR. CHATTERTON

5 Under pressure?

6 BY: DR. DOSCHER

7mind you, that as the pressure goes down and gas comes
8 out of solution, the viscosity will start going up. Now
9 never going to go very high, but we do change it from something
10 which is delightfully favorable viscosity ratio to something
11 that's not quite favorable, okay? If you wait for pressure
12 to go down. But now, in Prudhoe Bay I would expect water
13 fingering or water channelling to occur only from hetero-
14 geneity in lithology. In other words, a very gross change
15 in permeability between adjacent strata or a foot apart.

16 Ah..this has to be known..ah..it can be if you find that it
17 occurs, it can be avoided to some extent not completely.

18 Ah.. there are all sorts of remedies which we can call on for
19 close in support of..ah..channelling, like channel blocks and
20 silica and even cement. But if it is very bad we cannot
21 stop it. In other words, if you had a gross heterogeneity
22 like a fracture, we cannot stop it, but if we have that, this
23 reservoir is going to suffer even from gas expansion because
24 once the gas sees that it's going to channel through. I
25 hope we don't have it, there is nothing to suggest we have

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1 such gross heterogeneities here.

2 BY: MR. CHATTERTON

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

12 BY: DR. DOSCHER

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

17 BY: MR. CHATTERTON

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

20 BY: DR. DOSCHER

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

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

5 BY: MR. CHATTERTON

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

14 BY: DR. DOSCHER

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

17 BY: MR. CHATTERTON

18 Understood (indisc - simultaneous speech)

19 BY: DR. DOSCHER

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

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

5 BY: MR. CHATTERTON

6 Thank you. Thank you Mr. Chairman.

7 BY: MR. MILES

8 Mr. McKinnon.

9 BY: MR. McKINNON

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

12 BY: DR. DOSCHER

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

14 BY: MR. McKINNON

15and Dr. vanPoolen believes it's indicated?

16 BY: DR. DOSCHER

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

19 BY: MR. McKINNON

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

25 BY: DR. DOSCHER

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

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

6 BY: MR. McKINNON

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

9 BY: DR. DOSCHER

10you'd know exactly where to go.

11 BY: MR. McKINNON

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

15 BY: DR. DOSCHER

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

19 BY: MR. McKINNON

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

21 BY: DR. DOSCHER

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

24 BY: MR. McKINNON

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

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1 assume means four or five years into production.

2 BY: DR. DOSCHER

3 No, I didn't know...

4 BY: MR. McKINNON

5 You said a year or...

6 BY: MR. CHATTERTON

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

10 BY: MR. McKINNON

11 When is it too late economically for the companies?

12 BY: DR. DOSCHER

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

23 BY: MR. McKINNON

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

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There is no
page 197 and a
discontinuity is
evident. nk

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

8 BY: MR. MCKINNON

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

13 BY: DR. DOSCHER

14 Well, there are sometimes you never catch up with pressure.
15 I mean there are oodles of examples down along the gulf
16 coast where -- you've rather a small reservoirs, where you're
17 just -- where you're taking the oil out so fast you just
18 can't put the water in that fast. I mean, we say you play
19 catch up but this catch up means you're really going to
20 have to whale the water in which makes the problem a little
21 more difficult because the faster you try to put water in,
22 the more problems you have in overall integrity.
23 So, there has to be an optimum time. Certainly you can't do it
24 at zero -- at time zero on terms of a shear economics, you
25 can't wait twenty years in terms of what you can get out

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

4 BY: MR. MILES

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

6 BY: MR. PARR

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

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

12 BY: DR. DOSCHER

13 That's right.

14 BY: MR. MILES

15 Mr. Rogers.

16 BY: MR. ROGERS

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

24 BY: DR. DOSCHER

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

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

8 BY: MR. ROGERS

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

11 BY: DR. DOSCHER

12 That's right, that's right. And don't have any question about
13 the price of oil and gas going up. When I two years ago
14 suggested \$20 a barrel, I'm off by a couple of dollars, it's
15 above \$20. And, Mr. Schlessinger, yesterday suggested that
16 \$40 a barrel in uninflated costs in five or six years. Now,
17 the reason for this is simple, it's not because the OPEC is
18 greedy, and they are greedy, and everybody would be, but
19 we're running out of it. See this, this is the fact. We
20 have reached peak production in the world, not now, maybe
21 tomorrow. If you find something in Prudhoe Bay, may delay it
22 a year or two, but basically, the areas we can look and search
23 for oil we are running out of them. We'll need alternates
24 well before you go -- you finish producing at Prudhoe Bay.
25 So, your value of the goods is just going up.

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1 BY: MR. ROGERS
2 For that reason you'd suggest that the State pursue a course
3 of..ah..ultimate hydrocarbon recovery rather than, than..ah..
4 their current guess of what the ultimate dollar recovery is.
5 BY: DR. DOSCHER
6 I would, I would tend to opt in this direction.
7 BY: MR. ROGERS
8 Thank you.
9 BY: MR. MILES
10 I think Mr. Hayes is next.
11 BY: MR. HAYES
12 Dr. Doscher..ah..yesterday Mr. Hamilton and Mr. Green discussed
13 ..ah..water flooding and they were talking about their --
14 their plan to ..ah.. as I understood it to wait until such
15 time as the field produced about 100,000 barrels of water a
16 day as a byproduct and then reinject that. One of the reasons
17 they stated for doing that was because of the compatibility
18 of the residue water with the water that was already in the
19 field. The comment you made a little -- a few minutes ago,
20 talking of -- about how many -- how many years involved
21 accomplishing water injection, you mentioned a treatment
22 plant and pipe and that sort of thing, I inferred from that
23 that you're talking about a different type of water injection,
24 perhaps sea water -- my question is, is that what you're
25 talking about...

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1 BY: DR. DOSCHER

2 Yes.

3 BY: MR. HAYES

4and the second part of my question is, do you agree with
5 the..ah..plan as outlined by..ah..Mr. Hamilton and Mr. Green
6 as far as the proper way to ..ah.. sort of, ease into the
7 water flooding program?

8 BY: DR. DOSCHER

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

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

18 BY: MR. MILES

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

25 BY: DR. DOSCHER

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

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1 I'm willing to summarize.

2 BY: MR. MILES

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

5 BY: DR. DOSCHER

6 I'm concerned about the fact that in the..ah..one side of the
7 field we have high GOR's that won't go away. I'm concerned
8 that this may spread on us if we start because you recall it
9 was brought out yesterday, very clear, that coning or gas
10 breakout is occasioned by high rates and large pressure draw-
11 downs so that if higher rates are instituted and this
12 condition spreads, we may find more and more of the field is
13 going to high GOR's. So, again, because I don't know different
14 I'd say be a little cautious, we'll let 300,000 barrels mean
15 that much to you or the operators, this is a question that
16 the commission has to decide. If it's going to mean the
17 question of life or death or whether..ah..cash flow is
18 viable or not, you'd tend to nudge it the other way, but as
19 far as the needs of the United States, I think another
20 300,000 barrels isn't going to change our basic conditions
21 and..ah..matter of fact, I feel the sooner we start living
22 without that 300,000 barrels the better off we are because
23 we're not finding a replacement for it.

24 BY: MR. MILES

25 Thank you. Chat.

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1 BY: MR. CHATTERTON

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

8 BY: DR. DOSCHER

9 That's correct.

10 BY: MR. CHATTERTON

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

14 BY: DR. DOSCHER

15 Oh -- you're right on. When I said ready to operate, I meant
16 that. ah..we knew we could put the water in because there
17 may be a significant time, even with the water at the well
18 head before the water starts going in a uniform way.
19 Now, I hope that's not going to be long, I hope that the
20 injectivity tests which are being done now will teach us what
21 we need to know so that when that time occurs there won't be
22 a delay, but basically you're right. As a matter of fact,
23 you might even say that you want to wait until the pressure
24 builds up to some point in the reservoir. Again, I have to
25 say we'll have to wait until we see the 3-D studies to ascertain
this.

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AGO 532318

1 BY: MR. CHATTERTON
2 Alright, I'll try to clarify where I was going to get a
3 response to, even then, do we know whether we'll suffer
4 ultimate loss of recovery of black oil by permitting gas sales?
5 BY: DR. DOSCHER
6 Well, I hope the 3-D studies will have informed us.
7 BY: MR. CHATTERTON
8 Yea, I know, I know, I know, but it may show that you might
9 not even want to do it....
10 BY: DR. DOSCHER
11 You're absolutely right.
12 BY: MR. CHATTERON
13 I didn't want a closed answer to....
14 BY: DR. DOSCHER
15 You're absolutely right..ah..I beg -- this goes back to our
16 study, basically, of..ah..not -- but the runs we made with
17 the vanPoolen and Associates model which indicated that
18 water flooding and no gas sales gives you all that much more
19 oil.
20 BY: MR. CHATTERTON
21 Thank you. Okay, and I said next unrelated question, water
22 flooding and I'm using your definition of water flooding,
23 given that that became sort of a field wide technique 3-1/2
24 decades ago, where was water flooding started, it wasn't --
25 first -- what types of reservoirs, weren't they virtually

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1 depleted as far as primary recovery is concerned?
2 BY: DR. DOSCHER
3 No, the first reservoirs were..ah.. not depleted at all, they
4 were leaks in the casing in Pennsylvania in 1890.
5 BY: MR. CHATTERTON
6 Well -- well then -- let's say man -- well it's man made too,
7 on purpose by man....
8 BY: DR. DOSCHER
9 On purpose by man, you're right, that they were depleted....
10 BY: MR. CHATTERTON
11 3-1/2 -- okay, they were depleted reservoirs and basically
12 our history has improved the recoveries -- has been our long
13 standing histories, anyway, has been from depleted reser-
14 voirs and now we're boning up on the fact, well, maybe we should
15 have -- we should start early in the game.
16 BY: DR. DOSCHER
17 Again, I could point to say..ah..a couple of the reservoirs
18 in the North Sea -- or you put water in or the operators
19 putting water in very early and in Alberta you'll find
20 several reservoirs where..ah..water goes in just about from
21 day one, but there they have a experience level....
22 BY: MR. CHATTERTON
23but we don't have too much field history in back of us,
24 when I say too much....
25 BY: DR. DOSCHER
You're right.

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1 BY: MR. CHATTERTON

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

3 BY: DR. DOSCHER

4 Except in natural water drive we have....

5 BY: MR. CHATTERON

6 Oh, I understand, right. One other unrelated question, you
7 gave -- you expressed concern with the rate sensitivity between
8 1.2 and 1.5 million barrels a day, and you were alluding to
9 the fact that we had some gas tongueing and/or coning, what-
10 ever. Now, given that that gas coning and so forth and so on,
11 or tongueing occurred -- it occurred with X number of with-
12 drawal points, now -- we now have many more withdrawal points
13 in the reservoir to where possibly even the rate of withdrawal
14 from any single straw is dropping off, doesn't that not sort
15 of mitigate your concern?

16 BY: DR. DOSCHER

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

21 BY: MR. CHATTERTON

22 And were gaining...

23 BY: DR. DOSCHER

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

25 BY: MR. CHATTERTON

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

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1 month up there.

2 BY: DR. DOSCHER

3 Right, but on pretty big spacing. You see, I don't know at this

4 time whether it's a spacing phenomena or just what because

5 again -- I mean, our control is small again. Okay, and on

6 the east side the thing of concern is we have -- that's where

7 we have the most wells, where we have the most coning.

8 BY: MR. CHATTERTON

9 I guess what I'm saying is, do you agree with me we'd be on

10 very thin ice to -- with this expanding number at the rate of

11 six a month, let's say withdrawal points being drilled in and

12 put on production. Why, we're on thin ice if we pound

13 the table and say you can't go to 1.5 barrels....

14 BY: DR. DOSCHER

15Oh, there's no question of that, no, no question of that.

16 BY: MR. CHATTERTON

17 Thank you.

18 BY: DR. DOSCHER

19 And as I've said, I had no ice at all, I have only trends

20 that I'm extracting.

21 BY: MR. CHATTETON

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

23 BY: MR. MILES

24 Mr. Rogers.

25 BY: MR. ROGERS

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

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

8 BY: DR. DOSCHER

9isn't that what it is? We have no evidence to indicate
10 any serious negative effect. Maybe there will be after he does
11 some more work.

12 BY: MR. ROGERS

13Is there significant positive effect? Alright
14 (indisc - simultaneous speech)

15 BY: DR. DOSCHER

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

18 BY: MR. ROGERS

19 Thank you.

20 BY: MR. MILES

21 Mr. Parr

22 BY: MR. PARR

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

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

6 BY: DR. DOSCHER

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

19 BY: MR. PARR

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

24 BY: DR. DOSCHER

25 Yep, they do that.

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1 BY: MR. PARR

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

4 BY: DR. DOSCHER

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

14 BY: MR. PARR

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

20 BY: DR. DOSCHER

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

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1 or not but certainly as of two years ago there was -- we had
2 definite information and it's recorded in our report to you.
3

4 BY: MR. PARR

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

7 BY: DR. DOSCHER

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

9 BY: MR. PARR

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

13 BY: DR. DOSCHER

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

22 BY: MR. PARR

23 Thank you.

24 BY: MR. MILES

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

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

3 BY: DR. DOSCHER

4 I'll be here. Okay.

5 BY: MR. MILES

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

8 OFF RECORD

9 ON RECORD

10 BY: MR. MILES

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

16 BY: MR. HAYES

17 Limbo.

18 BY: MR. MILES

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

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1 witnesses that are out of town witnesses who have been kind
2 enough to come and join us. If we don't adjourn, it's my
3 intention to..ah..probably break at 5:00 and come back at
4 7:00 and hopefully we can..ah..hear from a couple of other
5 people who have indicated they would like to make a statement,
6 ..ah..following that just a general question and answer period,
7 it seems like there's a number of questions that have
8 arisen that people aren't real clear on and maybe give and
9 take between the witnesses might help, if the witnesses can
10 stay. If they can't, I'd certainly understand, I wouldn't
11 want to ..ah.. have anybody miss their plane, but this has
12 really been valuable set of hearings for me. I can't speak
13 for anybody else and I really appreciate everybody's help. Without fur
14 adieu then..ah.. Paul do you want to start introduce your
15 people and their various fields of expertise and go ahead
16 with your presentation in the manner that you choose.

17 BY: MR. NORGAARD

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

20 BY: MR. MILES

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

23 BY: MR. NORGAARD

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

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1
2 BY: MR. NORGAARD

3 That shows how well I'm prepared.

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

7 BY: MR. MILES

8 Okay, go ahead Paul.

9 BY: MR. NORGAARD

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

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

4 (Discussion regarding blinds)

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

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

24 BY: MR. MILES

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

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

3 BY: MR. NORGAARD

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

9 BY: MR. MILES

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

12 BY: MR. NORGAARD

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

16 BY: MR. MILES

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

18 BY: MR. NORGAARD

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

25 BY: MR. MILES

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

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

3 BY: MR. NORGAARD

4 In general, yes.

5 BY: MR. MILES

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

8 BY: MR. NORGAARD

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

10 BY: MR. MILES

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

13 BY: MR. NORGAARD

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

15 BY: MR. MILES

16 Thank you.

17 BY: MR. NORGAARD

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

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

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

25 BY: MR. MILES

Nobody asks leading questions on our committee except Chat.

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1
2 BY: MR. NORGAARD

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

7 BY: MR. DAVIES

8 Mr. Chairman, Members of the House Resources Committee,
9 Ladies and Gentlemen; my name is Brian Davies. I hold a
10 Honors Degree in Natural Sciences from Trinity College,
11 Dublin. I have been employed by British Petroleum and
12 Sohio in petroleum production and exploration activities for
13 16 years in the North Sea, Arabian Gulf, Columbia and
14 Alaska. Since 1971, I have been involved in the development
15 of the Prudhoe Bay Field, first, as District Petroleum
16 Engineer then as Sohio's representative to the Prudhoe Bay
17 Unit Planning Subcommittee in Anchorage. My current position
18 is Supervisor of Production Planning for Sohio and as such I
19 continue to be involved with the development plans for the
20 Prudhoe Bay Field. The purpose of my presentation to you
21 today is to describe production performance of the Prudhoe Bay
22 Field today. I will start with a summary of the field develop-
23 ment since the commencement of production in June of 1977.
24 Next I will briefly discuss the reservoir surveillance methods
25 that the operators are using to monitor the field performance.

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1 I will then discuss the production and pressure behavior,
2 the well performance, and the fluid contact movements in the
3 reservoir. I'd like to say right now that overall the
4 production performance has been good and essentially as
5 predicted. The Prudhoe Bay Field has been on sustained
6 production for just over two years. I apologize for the
7 switching on and off but we'll get through that here. Ah..initial
8 offtake from the field was restricted to about 720 thousand
9 barrels per day, because of the accident at Alyeska Pump
10 Station #8. After the repairs to the Pump Station were
11 completed in March of 1978, the rate of production was in-
12 creased to about 1.16 million barrels per day. Since then,
13 the performance of the pipeline system has been progressively
14 improved so that currently an offtake level of about 1.28
15 million barrels per day is being achieved. In the field,
16 we have maintained sufficient producing potential so as to
17 continuously produce at pipeline capacity rates. Early
18 production from the field was sustained by approximately
19 100 wells in total serving two flow stations in the Eastern
20 Operating Area and two Gathering Centers in the Western
21 Operating Area. By the end of the first three months of
22 production, all facilities were functioning satisfactorily.
23 And also, the flaring of gas ceased except during the
24 commissioning of new facilities and for emergencies caused by
25 minor upsets in the operation of the plant. Of the total of

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1 500 billion standard cubic feet of gas produced since
2 January 1, 1978, over 99.8% has been reinjected into the
3 reservoir or used as fuel. Because, we emphasize that,
4 99.8 has been reinjected into the reservoir or used as fuel.

5 BY: MR. MILES

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

8 BY: MR. DAVIES

9 Approximately as Dr. vanPoolen and the OGCC mentioned, over
10 90% has been reinjected into the reservoir.

11 BY: MR. MILES

12 So, roughly 9.8's used as fuel.

13 BY: MR. DAVIES

14 Yes, roughly. I don't have the breakdown on that, we can get
15 that for you, if you wish. Continuing on with the history
16 of development to date..ah..the third Gathering Center in
17 the Western Operating Area was commissioned in March of
18 1978, and the third Flow Station in the East came on stream
19 in March of this year. These facilities have enabled additional
20 wells to be progressively brought on production and so have
21 permitted offtakes to be distributed more evenly over the
22 field. We currently have nearly 200 wells drilled and
23 connected for production. Thus, over a period of two years
24 this represents a doubling of the number of wells available
25 for production. And we are proceeding with the further

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1 development and the operation of the Prudhoe Bay Field in a
2 manner which is consistent with the plans presented in the
3 May 1977 Pool Rules Hearing before the Oil and Gas Conservation
4 Committee. These plans permit the degree of flexibility that
5 is necessary for good reservoir and production management
6 control. Turning now to the question of reservoir surveillance.
7 In the previous testimony to the Oil and Gas Conservation
8 Committee in May 1977 the Unit owner companies described
9 their plans for reservoir surveillance. The owners recognized
10 that a comprehensive reservoir surveillance program was
11 necessary to provide the data needed to optimize the con-
12 tinued development of the field. The response of the
13 reservoir to production is indispensable in understanding
14 the recovery mechanisms and in checking the accuracy of
15 reservoir descriptions. In addition to frequent well testing
16 the owners proposed an intensive reservoir pressure measure-
17 ment effort, a program designed to monitor changes in gas
18 saturation and an evaluation of techniques to monitor changes
19 in the water saturation of the reservoir. Subsequently,
20 the Alaska Oil and Gas Conservation Committee issued
21 Conservation Order No. 145 which incorporates rigorous
22 surveillance requirements in the Prudhoe Bay Oil Rules. Over the
23 last two years this surveillance program has generated a
24 tremendous volume of field performance data. In our view
25 the level of reservoir surveillance and testing activity which

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

21 BY: MR. MILES

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

24 BY: MR. DAVIES

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

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

13 BY: MR. MILES

14 Thank you.

15 BY: MR. DAVIES

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

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

25 BY: MR. MILES

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

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1 BY: MR. DAVIES

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

3 BY: MR. MILES

4 No, I can.

5 BY: MR. DAVIES

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

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

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

11 BY: MR. MILES

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

14
15 Brian, did you say that in some areas in Prudhoe that the
16 pressure was higher than originally?

17 BY: MR. DAVIES

18 No, what I said was, turn back, in a pressure sink area,
19 perhaps we could put the thing back in here, in this pressure
20 sink area one year ago we recognized a significant
21 decline right in the core of the sink, so we reduced the
22 production off-take from that area. Ah..... Well,
23 we look at the map one year later, we see that the pressure
24 -- sink has not increased, there is no decline greater than
25 600 pounds. In some wells in that area, we are actually

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1 seeing an increase that are a bounce back. Let me put it to
2 you -- there are many...
3 BY: MR. MILES
4 so it's not bouncing back over the original pressure, it's
5 bouncing back from the drop of 600?
6 BY: MR. DAVIES:
7 Let's say a year ago we might have measured, for example,
8 550 pounds decline in a particular well and this year we'll
9 be measuring..ah..for example, 450.
10 BY: MR. MILES
11 Did you indicate what percentage of the field -- these are --
12 that's a substantial drop, is that right? 600 pounds
13 pressure?
14 BY: MR. DAVIES
15 That -- that is a substantial drop compared with the rest
16 of the field where we're looking at..ah..well, in that first
17 map, in the order of 200 pounds.
18 BY: MR. MILES
19 Okay, did you say here a percentage of the field that the
20 substantial drop was measured in?
21 BY: MR. DAVIES
22 Yes, I....
23 BY: MR. MILES
24 you say it's 6% or....
25 BY: MR. DAVIES

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

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

11 BY: MR. MILES

12 What does that mean for downstream recovery?

13 BY: MR. DAVIES

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

15 BY: MR. MILES

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

17 BY: MR. DAVIES

18no, it's no 6% drop....

19 BY: MR. MILES

20 Well it basic -- okay, it's -- yes, 6% of the oil in place.

21 Is that right?

22 BY: MR. DAVIES

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

25 BY: MR. MILES

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

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

5 BY: MR. NORGAARD

6 Mr. Chairman, we will be addressing that directly in testi-
7 mony, a little later, if that's alright. We can answer it
8 now if you like.

9 BY: MR. SMEDLEY

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

16 BY: MR. MILES

17 Mr. Chatterton.

18 BY: MR. CHATTERTON

19 I am on the point of clarification -- if your going to
20 touch on this and that, why just say so, and go.

21 Obviously, I'm looking at iso -- pressure lines there, is
22 that correct?

23 BY: MR. DAVIES

24 That's right.

25 BY: MR. CHATTERTON

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

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

9 BY: MR. DAVIES

10 Yes...

11 BY: MR. CHATTERTON

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

15 BY: MR. SMEDLEY

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

17 BY: MR. CHATTERTON

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

19 BY: MR. MILES

20 Mr. McKinnon.

21 BY: MR. MCKINNON

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

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1 pressure loss is confined between those shale layers.

2 BY: MR. DAVIES

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

9 BY: MR. MCKINNON

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

12 BY: MR. DAVIES

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

18 BY: MR. MCKINNON

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

21 BY: MR. DAVIES

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

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1 BY: MR. MCKINNON

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

4 BY: MR. DAVIES

5 That's right.

6 BY: MR. MCKINNON

7because the well would break and record something that
8 approaches very close the highest pressure that it sees or
9 at least a composite of the two. So, if the whole interval
10 were open, that 600 pound pressure sink might look like 200
11 pounds and that's what Brian's dealing with when he says you
12 have to look at both the horizontal and the vertical -- make
13 a -- I guess it's just a straight calculation on what is
14 effected.

15 BY: MR. SMEDLEY

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

20 BY: MR. NORGAAARD

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

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

6 BY: MR. McKINNON

7 Has this situation shut down some wells?

8 BY: MR. SMEDLEY

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

14 BY: MR. McKINNON

15 Did..ah..

16 BY: MR. MILES

17 Joe, are you done or.....

18 BY: MR. McKINNON

19 Yeah....

20 BY: MR. DAVIES

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

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

10 BY: MR. MILES

11 So, the gas is actually sinking?

12 BY: MR. DAVIES

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

17 BY: MR. MILES

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

21 BY: MR. DAVIES

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

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1 what happens when you drill the wells.

2 BY: MR. CHATTERTON

3 Brian, clarification question. If the mobility, relative

4 permeability, was equal for the oil and the gas, would

5 you expect to see that?

6 BY: MR. MILES

7 Can I pass that one?

8 BY: MR. DAVIES

9 Paul can answer it.

10 BY: MR. SMEDLEY

11 I'll try that one. The..ah..the mobility, the gas being

12 much more mobile, contributes to this problem, the density

13 difference between oil and gas combats this phenomena, in

14 other words, the density difference is trying to keep that

15 contact very sharp so you've got kind of opposing forces --

16 that you really try to balance. (indisc.)

17 BY: MR. CHATTERTON

18 Thank you.

19 BY: MR. DAVIES

20 Okay, so, as one produces, through the perforations, the

21 oil - gas/oil contact starts the coning down until eventually

22 gas is produced through the uppermost part of the perforated

23 interval. This is the fully developed gas core and

24 when -- when you refer to a well coning gas, that's what's

25 happening, you develop the cone so gas is being produced

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

14 BY: MR. MILES

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

17 BY: MR. DAVIES

18 What's that?

19 BY: MR. MILES

20you suck some of the gas cap up into the oil or does
21 technology prohibit that if your gas cone come to the top
22 holes where you're drawing the oil out, what happens?

23 BY: MR. DAVIES

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

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1 BY: MR. MILES

2 It just goes right up in the top.

3 BY: MR. NORGAARD

4and you just produce the higher amount of gas. That's
5 it. The (indisc.) gets reinjected back into the gas cap.
6 That's what happens and that's the most serious thing that
7 can happen to you.

8 BY: MR. MILES

9 Thank you.

10 BY: MR. SMEDLEY

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

15 BY: MR. DAVIES

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

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

9 BY: MR. PARR

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

12 BY: MR. DAVIES

13 No.

14 BY: MR. PARR

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

18 BY: MR. DAVIES

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

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1 BY: MR. PARR

2 Well, maybe I don't quite understand you but if I under-
3 stood your statement. Ah..because you use this 200 and
4 260 feet distance, you reduce the production and that
5 you compensate for this by drilling more wells. Now..ah..so
6 what is that doing in terms of benefits to the reservoir
7 which is what I understood. It appears to me you're pulling
8 the same amount of oil out of that reservoir in either case,
9 right? If you have ten wells pulling out 10,000, that's
10 100,000, one well putting out 100,000 that's 100,000. So,
11 I mean -- what's -- I don't understand how you're
12 gaining anything here in terms of protecting the reservoir.

13 BY: MR. DAVIES

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

22 BY: MR. NORGAARD

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

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

10 BY: MR. SMEDLEY

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

14 BY: MR. PARR

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

17 BY: MR. SMEDLEY

18lower capacity.

19 BY: MR. PARR

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

23 BY: MR. SMEDLEY

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

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

23 BY: MR. PARR

24 Thank you.

25 BY: MR. NORGAARD

I hope we answered it close enough.

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1 BY: MR. CHATTERTON

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

7 (laughter)

8 BY: MR. PARR

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

21 BY: MR. SMEDLEY

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

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

3 BY: MR. PARR

4 Thank you.

5 BY: MR. SMEDLEY

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

11 BY: MR. ROGERS

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

14 BY: MR. NORGAARD

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

19 BY: MR. ROGERS

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

23 BY: MR. SMEDLEY

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

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

7 BY: MR. ROGERS

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

10 BY: MR. SMEDLEY

11 That was our decision but it was a program prior to produc-
12 tion startup was discussed with the Oil and Gas Conservation
13 Commission and they endorsed it.

14 BY: MR. NORGAARD

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

16 BY: MR. ROGERS

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

19 BY: MR. NORGAARD

20 Yes.

21 BY: MR. CHATTERTON

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

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

5 BY: MR. DAVIES

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

7 BY: MR. MILES

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

10 BY: MR. DAVIES

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

13 BY: MR. MCKINNON

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

16 BY: MR. DAVIES

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

22 BY: MR. SMEDLEY

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

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

16 BY: MR. DAVIES

17 Let me answer the question of the..ah.. the movement of the
18 fluid contacts. As I mentioned previously, the neutron tool
19 has been proven to be a highly effective method for monitor-
20 ing changes in gas saturation in the reservoir. And based
21 upon the results of these surveys, we interpret that the
22 overall movement of the gas/oil contact is of the order of
23 15-20 feet per year, on average. This is certainly very
24 close to what was predicted prior to production, for the
25 oil offtakes we have maintained to date. We have also

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

11 BY: MR. MCKINNON

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

16 BY: MR. DAVIES

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

21 BY: MR. MCKINNON

22 Oh, alright, I confused what you were saying.

23 BY: MR. DAVIES

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

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

11 BY: MR. SMEDLEY

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

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

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1 review the reservoir study results which then led to the
2 Prudhoe Bay operating plan, I'll highlight various develop-
3 ment options that we studied, such as well spacing, arti-
4 ficial lift, waterflooding, and so forth. And, I'll also
5 review sensitivity studies which describe the impact of oil
6 and gas offtakes and the time of water injection on the
7 ultimate oil recovery.

8 BY: MR. MILES

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

12 BY: MR. SMEDLEY

13 The 3-D model was discussed at the Pool Rules Hearing, as
14 you will hear later. The results that we used for the
15 sensitivity studies were based on -- well, it's really what
16 we call a three-dimensional cross-section, it's a cross-
17 sectional type model, it's not what you would think of as a
18 full three-dimensional model of the field, I think I can
19 explain this maybe a little bit better in the context of the
20 total testimony. Those model results and the ones I'll
21 present today are a matter of record, of public record, they
22 were included in our testimony at the May '77 hearing, May,
23 1977 hearing.

24 BY: MR. MILES

25 Are they laid out like the ones from -- vanPoolen is the

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

3 BY: MR. SMEDLEY

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

16 BY: MR. MILES

17 Okay, can you send me those?

18 BY: MR. SMEDLEY

19 Yes.

20 BY: MR. MILES

21 Okay.

22 BY: MR. SMEDLEY

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

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

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

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

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

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

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

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1 efficient natural depletion process of gas cap expansion and
2 gravity drainage is dominating over most of the reservoir.
3 Indeed, if an inefficient, solution gas drive type mechanism
4 were dominant, as some have suggested, the pressure decline to
5 date would be in the order of 400 psi, or about twice the
6 measured value. Okay, with that comparison of the measured
7 and predicted performance as a backdrop, I would like to --
8 turning to the next figure, I'd like to review the results
9 of the studies which were presented at the Oil and Gas
10 Conservation Committee Hearing, and provided the basis for
11 the current operating plan for the Prudhoe Bay Unit. Testi-
12 mony presented at that hearing indicated that ultimate oil
13 recovery from the Main Area Sadlerochit reservoir would be
14 approximately 40% of the original oil-in-place with full
15 development and planned oil and gas offtake rates.

16 BY: MR. MILES

17 What's full development?

18 BY: MR. SMEDLEY

19 Full development means we drill all the wells and install all
20 the planned facilities and it

21 BY: MR. MILES

22 What are planned facilities?

23 BY: MR. SMEDLEY

24 That's what -- I'm going to talk about some of those as I go
25 down this chart. As we pointed out at the hearing, enormous

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1 future investments would be required to achieve that
2 recovery level. The first area that -- that's very difficult
3 to read, that chart, for sure if you could push it down flat
4 maybe. These are the facilities additions, Mr. Chairman,
5 that are inherent in that. Ah -- completing development
6 drilling on 160-acre spacing rather than 320-acre spacing
7 which was basically what was taking place at the time of the
8 hearing, is projected to increase recovery about 4% of the
9 original oil-in-place. The operators have been proceeding
10 with development drilling, as Brian indicated, they have increased the
11 producing well count from about 100 at start-up to about 200
12 today. However, there are some 300 additional wells which
13 will be required for full development. The drilling and
14 equipping of these wells to produce will cost in the order of
15 \$2 to \$3 billion. Studies are underway now to evaluate the
16 proper development limits and well density for the fields.
17 The second potential facility addition shown is a low pres-
18 sure gathering system to allow reduced wellhead producing
19 pressures. The study indicates an additional recovery
20 potential of about 5% of the original oil-in-place. Total
21 cost for such a system field-wide has been estimated at \$1.5
22 to \$2 billion. Now, the first increment of this facility
23 was recently approved by the Unit Owners and equipment has
24 been ordered for installation at Flow Station 2 in the
25 eastern operating area in 1982. Other increments must be analyzed,

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1 designed and justified. The study indicates additional
2 recovery potential of about 5% for an artificial lift system
3 at Prudhoe Bay. Again, the cost is estimated to be in the
4 order of \$1.5 to \$2 billion, and although this system is at
5 a very early stage of planning, we expect to install such a
6 system when needed to maintain production rates. The studies
7 also show a potential of up to 2% additional recovery by
8 injecting the water that is produced with the oil into
9 portions of the Sadlerochit Reservoir which experienced poor
10 natural depletion recovery. Depending on the final design,
11 this system has been estimated to cost in the order of \$1
12 billion. The Unit Owners recently approved funds for the
13 first increment of produced water injection. Equipment for
14 this system has been ordered and we expect the first increment
15 to be operational in the Eastern Operating Area in 1981. The
16 produced water injection system will be expanded as volumes
17 increase and as production performance allows refinement of
18 the waterflood design. Source water injection systems also
19 offer potential to increase ultimate oil recovery. Exxon's
20 studies indicate the additional recovery may be in the order
21 of 4% of original oil-in-place, as shown on this chart. Sohio,
22 on the other hand, has estimated that the additional recovery
23 from source water injection could be as much as 7% of the
24 original oil-in-place, and both of these figures were
25 presented at the hearing and are a matter of public record.

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1 The cost of the source water injection system has been
2 estimated to be in the order of \$1.5 to \$2 billion. Dave
3 Griffiths, the next speaker will describe studies and tests
4 which will cost in excess of \$40 million which the Unit
5 Owners have been engaged in for the past two years to evaluate
6 and design a water injection system. Estimated recovery
7 without these development additions described would be approxi-
8 mately 20% of original oil-in-place. So, the remaining half
9 of forecast recovery depends upon additional facilities and
10 investments which will cost well over \$10 billion, just to
11 develop the main Sadlerochit Reservoir.

12 BY: MR. ROGERS

13 How many barrels do you get per -- per each percent?

14 BY: MR. SMEDLEY

15 Ah...it's about 200 million, in that order.

16 BY: MR. ROGERS

17 Thank you.

18 BY: MR. SMEDLEY

19 This future investment of in excess of \$10 billion compares
20 to less than \$4 billion that's been spent on the field
21 development today. These are enormous future investments
22 which must be justified and facilities designed based on
23 field performance data, detailed studies, and economic
24 factors. As I have indicated, the Unit Owners are already
25 proceeding with several of these projects and others are

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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. NOILGAARD

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

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1 what the investment....
2 BY: MR. MILES
3 there was never a dollar figure put on it?
4 BY: MR. NORGAARD
5 Yes, we had dollar figures but they were terribly, erroneously
6 wrong.
7 BY: MR. MILES
8 Until when?
9 BY: MR. NORGAARD
10 They were low, like everything we did.
11 BY: MR. MILES
12 How much low.
13 BY: MR. NORGAARD
14 I'm sorry I really -- I really can't....
15 BY: MR. MILES
16 You know -- we're talking about roughly, Larry said 10 billion,
17 how much were we talking about then?
18 BY: MR. NORGAARD
19 I would speculate that they were probably half, our estimates
20 were probably half, at that point in time. Well, they've
21 changed....
22 BY: MR. MILES
23 What was that point in time, when was it.
24 BY: MR. NORGAARD
25 Let's say four or five years ago.

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1 BY: MR. ROGERS

2 And revenues were about one-quarter?

3 BY: MR. NORGAARD

4 Things have changed dramatically all the way around.

5 BY: MR. ROGERS

6 You mentioned both on the well spacing and produced water..

7 ah..east -- the east operating -- are you -- do I get from

8 that you're going to be using as additional recovery earlier

9 in the eastern section?

10 BY: MR. SMEDLEY

11 The -- it's planned that the produced water injection will go

12 in early -- one year earlier, as we currently envision it in

13 the eastern section and the west.

14 BY: MR. ROGERS

15 Is there any -- since this May, 1977, are there any new

16 technologies that might push us beyond the..ah..40% recovery?

17 BY: MR. SMEDLEY

18 Not new technologies, I don't think, but....

19 BY: MR. ROGERS

20 Are there new -- ones that have become economic because of

21 the higher value of oil.

22 BY: MR. SMEDLEY

23 No, sir ..ah..you're thinking in terms of like a tertiary

24 recovery process or something like this I assume, and no,

25 there are none currently.

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1 BY: MR. NORGAARD

2 I think the answer to that may be expanded a little bit. I
3 think, that's a continually changing target as people learn
4 more from other areas and also as the economic environ-
5 ment of the world changes, but there's one thing for sure,
6 that Prudhoe was not the place to experiment. It's a high
7 cost area and experimenting should be done in something that's
8 relatively safe and (indisc) so we look very heavily to other
9 similar environments to -- to see what's happening and to
10 (indisc - simultaneous speech)

11 BY: MR. ROGERS

12 Sub-surface environments, what areas of the world are similar?

13 BY: MR. NORGAARD

14 Well, there are a number of reservoirs that are not dissimilar
15 from Prudhoe Bay -- I went for many years, it's probably too
16 late to try anything with it, but there are a number of
17 reservoirs that you can use as, certainly not parallels, but
18 it's something that you could use as a go by. I don't think
19 that there's another Prudhoe Bay in the world, but there's
20 reservoirs with character in (indisc). Larry mentioned that
21 high quality characters in Prudhoe Bay, there's other reser-
22 voirs in the world that same, a similar high quality
23 (indisc)

24 BY: MR. ROGERS

25 Sir, when did you do your first preview runs? When did you

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1 build your model?

2 BY: MR. NORGAARD

3 We built the model in 1976 and ran it in 1976.

4 BY: MR. PARR

5 I realize that every field is unique, I understand that, but
6 isn't there sort of a general rule of thumb around the world
7 that 35 to 40% of your -- 35 to 40% of your reservoir is
8 recoverable? Generally, speaking?

9 BY: MR. SMEDLEY

10 No sir, that's how I -- for an overall average.

11 BY: MR. PARR

12 I - we've been lead to believe that in previous testimony
13 that -- not necessarily this particular set of hearings, but
14 one we've had in the past. Now, I'm just wondering when I
15 see that 20% on there..ah..did the -- your operators -- your
16 Owner companies ever consider any possibility of only getting
17 20% and stopping?

18 BY: MR. SMEDLEY

19 Yes sir. We have since the very early studies, very early,
20 that's -- I mean, since our studies in the early 1970's where
21 we started getting pretty sophisticated with reservoir modeling
22 and interestingly those days have not changed too dramatically
23 even up to now, since that point in time when I've been involved
24 in this type of work on this field..ah.. the plans for
25 development, the types of things you see..ah..facility

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1 additions and so forth have been contemplated. We never
2 really ever expected to stop development when we had only
3 320 acre spacing since the -- that was -- you drill 320 acre
4 wells before you drill 160 acre wells, just like you would
5 drill 160 acre wells before you drill 80 acre wells. So, at
6 some point in time we had those kinds of wells, but it was
7 never envisioned that we would stop.

8 BY: MR. PARR

9 Let me ask my question in another way -- then. The impression
10 you gave in going through this chart is that you're going to
11 start off with 20% recoverable and then at each one of these
12 additional capabilities the Owner companies are going to
13 look at this on say a cost benefits ratio, bases or something
14 of that sort, and decide -- you know -- whether it is economi-
15 cally feasible for the company to do it, and so you might get
16 20, you might decide that only the first 160 acre wells is the
17 one you'll do and stop at 24, or you got down through that one
18 and then you decided it wasn't economically feasible so you
19 might stop at the second item which is 29% and so forth.

20 But, I'm getting -- now, I'm understanding that that never was
21 contemplated and is not now contemplated, is that correct?

22 BY: MR. SMEDLEY

23 It was -- the studies were sophisticated enough that -- it was
24 anticipated that we would be able to go to this type of
25 development. In terms of presenting our estimate of recovery

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1 we pointed out that there are alternate development schemes
2 possible, several of which may go after the same oil. In
3 other words, there are different ways to get there. This is
4 one, I don't like scenario, but that's one scenario for
5 getting to 40% recovery. There are others, perhaps involving
6 closer well spacing, 80 acre spacing, this type of thing, and
7 as we mentioned at the Pool Rules Hearing, based on a wide
8 variety of studies where we have varied the reservoir descrip-
9 tions, would Prudhoe reservoir look like this or will it look
10 like this. We could see that 40% recovery appeared to be
11 reasonably achievable under varying reservoir descriptions, but
12 the way to get there, the best way to get there, was different
13 with different descriptions, and so, we gave the 40% recovery
14 as our best estimate. We left some flexibility in the steps
15 we take to get there and we'll take the optimum steps as we
16 learn more and more about the reservoir.

17 BY: MR. PARR

18 In other words then, it may not really cost the \$10 billion
19 to get that 40%? You might take some other steps which don't
20 cost that much money, is that correct? You got \$10 million,
21 this isn't that short that you told us, but you just said
22 that there are other possible ways to do it.

23 BY: MR. SMEDLEY

24 That's right. It is conceivable, and on the other hand it's
25 also conceivable it may cost way more than \$10 billion.

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1 BY: MR. PARR

2 Let me -- in other words, if you don't use the systems, the
3 steps shown here, if you use other ones that may not even cost
4 you the \$10 billion.

5 BY: MR. NORGAARD

6 Let me offer an comment here if I may, I don't like to inter-
7 ject myself, but I think that as far back as we go in the
8 direct testimony before Conservation Committee, yourselves,
9 federal government and whatnot, the plan for the field has
10 always been to fully develop the field, and when we say fully
11 develop the field, that means doing essentially all of those
12 things, include waterflooding. That has been the plan and
13 it -- you probably -- the May, '77 hearing, we said that we
14 were proceeding along that plan, we just needed some produc-
15 tion history to verifying certain things that we had specu-
16 lated and therefore we have always planned on doing all of
17 this. The exact timing and the exact sequence, that's some-
18 thing we will learn as we go, but the plan has always been to
19 do all of that, we have always looked for 40% recovery and
20 this is just one way of isolating and saying this is what
21 each of these contributes. It's almost an academic exercise
22 in a certainty.

23 BY: MR. PARR

24 Thank you, that's the kind of answer I wanted.

25 BY: MR. MILES

When -- Paul, as long as you're

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1 in this discussion, when do you plan to begin waterflooding?
2 BY: MR. NORGAARD
3 Well, the -- thing you deal with is what does waterflooding
4 mean and when we begin to inject water -- no, when we plan
5 to begin injecting water into the producing formation will be
6 in 1981 and it will be in the Flow Station 2 area, the area
7 where we have seen the greatest pressure, highest continuity
8 in shales, therefore the most obvious and logical place to
9 start waterflooding.

10 BY: MR. MILES
11 That's just a - that's just a little trickle in comparison.
12 I mean, that's just a -- what Dr. vanpoolen said, the
13 goop that comes up, goes back down to 100 thousand barrels
14 (indisc. - simultaneous speech)

15 BY: MR. NORGAARD
16 And it could be when we get there, sir, we will choose to
17 augment that in some fashion. We're looking at that and we'll
18 continue to look at that. When we would be looking at going
19 to a major outside source

20 BY: MR. MILES
21 Yea, that's what I'm

22 BY: MR. NORGAARD
23 the earliest possible would be in '84, and Dave Griffiths
24 will give you a lot of detail on that in just a minute, but
25 the timing that you ask, would be the earliest possible is

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1 '84 and that's certainly our objective, unless something
2 trips us up very badly between now and then.

3 BY: MR. MILES

4 Thank you, that's the objective, but.....

5 BY: MR. NORGAARD

6 There's no way that we see we can get there before '84.

7 BY: MR. MILES

8 What might trip you up?

9 BY: MR. NORGAARD

10 A permit application, just physical constraints, and
11 material delivery times. The -- some very, very strange
12 reservoir interpretations between now and then. We've done a
13 lot of work, but we still have a lot to do, i.e., history
14 matching and carrying forward that..... Those are the three
15 main areas and Dave Griffiths will speak to each of those
16 in some detail.

17 BY: MR. MILES

18 It's costs -- costs are not a main factor.

19 BY: MR. NORGAARD

20 I'd have to say I don't believe right now -- I'd have to
21 look at it again, but I don't believe right now that the
22 cost or who -- how it's financed is material at all. We
23 really are worrying the permit problem -- the design problem
24 and materials and then finally the reservoir analysis problems.
25 And I think in each of those, we are targeting ourselves so that

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1 they coincide, we hope, about a year from now, we'll consider
2 it a year from now, and at that point in time everything will
3 fit and we'll move forward.

4 BY: MR. MILES

5 Thank you very much.

6 BY: MR. NORGAARD

7 But, Dave will elaborate on that point.

8 BY: MR. CHATTERTON

9 Yea, I'd like to go to Larry for a minute, if I can. In your
10 1977 presentation in May, I've always had a little bit of
11 a problem with these two charts because you also testified
12 that that primary recovery while you were anticipating about
13 36% recovery, yet you got 20 down there. I think you were
14 trying to sell well spacing with that one, and you were trying
15 to sell that you were going to recover a lot of oil with the other
16 guy that testified. I've never been able to correlate the --
17 this chart with your other statement, not yours personally,
18 but other statements made by the operators, that the primary
19 recovery is going to be 36%, waterflooding ultimate recovery
20 is going to be 4% -- 40% and of course, obviously, the 4%
21 differential is not any great, horrendous incentive to proceed
22 to that point, but I've never been able to figure where you get the 20.

23 BY: MR. SMEDLEY

24 Okay, let me try it, one more shot at this thing. Ah..the
25 reason for this chart is to show several things that are

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1 reasonably similar decisions that have to be made, that are
2 being made, but in a logical course, to get from where we are
3 right now which is with adequate facilities and wells and so
4 forth, to get about 20% of the oil-in-place out to where we
5 think we will end up and that is with wells and facilities
6 and so forth to get 40% of the oil-in-place. So, it's --
7 really its primary intent is to say it -- waterflooding is
8 one of the decisions we have to make, in terms of money
9 the inference is that we're not willing to make that decision
10 because it's a large capital investment. These other items
11 are equally large capital investments.

12 BY: MR. CHATTERTON

13 How do you get from 20% to the 40%, what else can you do there?

14 BY: MR. KOONZ

15 This is primary recovery here.

16 BY: MR. CHATTERTON

17 I understand, and if you say it's 36% in your testimony
18 (indisc.- simultaneous speech)

19 This one always just confused the hell out of me.

20 BY: MR. NORGAARD

21 I don't -- you're alone in that. I think the main thrust here is
22 that the 20% is not a primary number. The 20% is a primary
23 number under a given set of assumptions and that assumption
24 is that we don't do anything more in Prudhoe Bay.

25 BY: MR. CHATTERTON

....The oil in 1977, I think....

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1 BY: MR. NOORGAARD

2what, no, if we don't do anything more in Prudhoe Bay,
3 that right now we quit. Matter of fact, that was in 1977
4 that we quit. and that's an unrealistic assumption. We all
5 know that's unrealistic and therefore, this was an attempt
6 to say there are other options or there are several require-
7 ments to get the primary recovery out and this is a listing
8 of them and what we suspect will be recovered with each one
9 of these. Now, there's another point here that those numbers
10 the fours and fives and whatnot, are certainly not rigorous
11 because when you do all of those things they're interrelated
12 and you can't say which barrel of oil was recovered from
13 which one of those phenomena. That is just a guide in how
14 much oil each of these will deliver to the tanks. Now, did
15 that help?

16 BY: MR. CHATTERTON

17 That helps. I think the point that you've made is the impor-
18 tant point, that that 20% was your estimate of the recovery
19 from Prudhoe Bay in May, 1977 if you walked away and did
20 nothing more.

21 BY: MR. NORGAAARD

22 We did no more, put no more money into it.

23 BY: MR. CHATTERTON

24but with continued development drilling, continued with
25 waterflooding, continued with this and everything as you are,

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1 you could get to 40%, if, with waterflooding. Without water-
2 flooding you would only get the 36% and your testimony, if
3 you correlate it in that fashion fits, but your explanation
4 did not.

5 BY: MR. SMEDLEY

6 The way I would have walked down through that is to say,
7 alright, we were at 20% recovery by drilling the additional
8 wells, get down to 160 acre wells which is some 500 in the
9 field, we will get up to 20+4, 24, if we -- by adding a little
10 pressure gathering system, we get up another five to
11 29. By adding an artificial lift system we add another five
12 we get up to 34, that's the natural depletion recovery with-
13 out produced water returned to the reservoir. If we return the
14 produced water to the reservoir we get another two, that's
15 the 36 (indisc - simultaneous speech)

16 BY: MR. CHATTERTON

17 There you are, okay.

18 BY: MR. MILES

19 I told you Chatterton was the only one who grasped this.

20 BY: MR. MILES

21 But he asks leading answers.

22 BY: DR. DOSCHER

23 Mr. Miles, may I ask one clarifying question? You didn't mean
24 that you'd walk away in 1977, you meant completed at 320
25 acres, didn't you.

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AGO 532395

1 BY: MR. SMEDLEY

2 Yes, that would be with some 200 and some odd wells for 320

3 (indisc - simultaneous speech)

4 BY: DR. DOSCHER

5 Fine, it didn't mean that -- it didn't mean to stop cold
6 in 1977.

7 BY: MR. SMEDLEY

8 That's right. It was 320 acre development, if you stopped at
9 320 acre development.

10 BY: MR. ROGERS

11 Since, since a number of these methods are pretty high cost,
12 and you're talking about \$2 billion each on the average and
13 some of them, I don't know which ones, waterflooding apparently
14 is time sensitive, the earlier the better, and I don't know --
15 I don't know about the others. And, is the -- since the
16 recovery comes later on, it's not going to be a early re-
17 covery, obviously, your cost is higher, your internal cost
18 is higher if you do it sooner than if you -- you hold off for
19 a year even though the recovery might be higher if you did
20 it sooner. I guess -- since the State's discount rate is
21 probably lower than the industry, if the State were to offer
22 to participate in the financing would that speed up any of
23 the..ah..any of the secondary recovery techniques.

24 BY: MR. NORGAARD

25 I think the answer to that is basically that we are on a

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1 critical path right now. Ah..with '84 as being the earliest
2 possible start-up to take things in a logical sequence and
3 we would have to look at it closer than what we have right
4 now, but the general answer was no it would not speed it up.

5 BY: MR. ROGERS

6 So, you're saying then that the financial aspects are not
7 the limiting things on..ah..I'd say waterflooding, it would
8 be equipment or materials.

9 BY: MR. NORGAARD

10 That would be the case at this point in time, yes, as we
11 perceive it right now. Come 1980 though, the answer might
12 be a little different, if something strains, if the purely
13 unforeseen happens between now and then. We don't visualize --
14 we don't envision that the plans for water injection, we
15 fully expect to moving forward in 1980.

16 BY: MR. McKINNON

17 Can I ask four questions, if I may. When you do your economic
18 analysis, cost benefit, what discount rate do you use for the
19 industry?

20 BY: MR. NORGAARD

21 That's -- that's really an impossible question to answer in
22 many (indisc.) because first of all there's three companies
23 involved and therefore, there's probably three different
24 considerations, but certainly industry in general, and I
25 believe that they have testified, several of our companies,

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1 have testified a number of times in a number of places, we
2 do look at discount rates, we are looking at discount rates,
3 they're basically industry averages, if you will, which is
4 really not just oil industry but total domestic industry --
5 you know, all industry, automobiles, everything else and that
6 is influenced, of course, by the value of money, what it costs
7 to borrow and so it varies depending on which year you're
8 talking about and I believe, that this particular point in
9 time, it's somewhere 13, 14, 12 somewhere like that, is the
10 kind of numbers that industry is looking at..ah.. in
11 generating good prospects in moving forward. I really don't
12 know what the prime rate is right now, but I think it's over
13 12. It varies, and I don't think that there's a pat answer to
14 that question.

15 BY: MR. MCKINNON

16 Your economic analysis doesn't use an average for the industry,
17 it uses an average -- an average for the oil industry, you
18 use an average for industry in general.

19 BY: MR. NORGAARD

20 Again, I think the economic analysis each company has its
21 own, but in general, for -- they would be reflected.

22 BY: MR. MCKINNON

23 What is your companies....

24 BY: MR. NORGAARD

25 To be very honest, I can't give you answer on that right now

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1 because again it's a changing thing and I really don't know
2 what it is. That isn't the only criteria, that isn't the
3 only parameter that goes into the decision making property
4 and I'm not in a level in our company where I can give you
5 all the answers because I really don't know. But certainly,
6 I'm going to step - take a step further than you questioned,
7 if I may, and it goes into what -- at I and I think, we as
8 oil companies perceive them in Prudhoe Bay field. Ah..several
9 questions have come forward here with respect to the rate of
10 return and the difference the State has versus what industry
11 has in their rate of return criteria and there can be instances
12 and there probably have been and will be instances where that
13 does create differences, different desires, different objec-
14 tives and different opinions. I would be naïve not to say
15 that that is true. I think in the Prudhoe Bay Field, though,
16 we happen to be very fortunate, in that the reservoir is a
17 high quality reservoir. The work -- at least I heard from
18 Dr. vanPoolen and Dr. Doscher also mentioned, the work that
19 we have seen suggests that the decision process and the
20 decision timing that we're going through on this, is not
21 sensitive to these discount factors. It appears as the
22 reservoirs are -- sufficient quality, the decision appears to
23 be, like it will be clear enough so we won't get into differ-
24 ence of opinion or conflict because of the discount rate.
25 Now, I can't guarantee that, but that's certainly what I

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1 heard from Dr. vanPoolen and I believe from Dr. Doscher,
2 and tied to our own studies we're talking about at this
3 point in time. Our plans are to waterflood it as early as --
4 we physically can do that. I think that is consistent with
5 everything I heard and now I can't guarantee that's what is
6 going to happen because a ducks could fall on the road
7 between now and 1984, but that certainly is what we expect.

8 BY: MR. McKINNON

9 At what point -- is...ah..what point does waterflooding
10 become economically unfeasible, in some point it's just not
11 worth doing?

12 BY: MR. NORGAAARD

13 You know -- again, I'll answer it. It's a technical question
14 but I'll answer it because I really think it has overtones
15 in it. If you can predict to me what the world is going to
16 be in 1990, I might be able to answer your question. I don't
17 think that there is a point in time when one can say. It's
18 uneconomic to waterflood a reservoir or a facility because
19 it's tied so much to what it's going to cost, in what the value of
20 the product your going to get and therefore, I don't think
21 we can sit here today and..ah..make a realistic prediction.
22 I think we can say though, and I believe it will be said
23 later on, that in the realistic environment waterflooding
24 within any time frame that we could realistically accomplish
25 it or that we would consider, has simply no impact on the

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AGO 532400

1 Prudhoe Bay performance and I believe that's what you're
2 looking for in your question. In other words, whether it's
3 in '84, or '86, or '87, it realistically has no impact on
4 Prudhoe Bay on the recovery from the field, that we've been
5 able to see, and if I understand -- I mean, if what's been
6 done in that's true of what other things?

7 By; MR. McKINNON

8 If you start water injection in 1984 it's going to get you an
9 extra billion -- billion barrels.

10 BY: MR. NORGAAAR

11pick a number...

12 BY: MR. McKINNON

13you start at 1985, it's not going to get you a billion
14 barrels.

15 BY: MR. NORGAAARD

16 Well, you've gone outside, I believe, the realistic range

17 BY: MR. McKINNON

18that's what I'm trying to understand, what the range is.

19 BY: MR. SMEDLEY

20 There were study results presented at the hearing, I know we
21 varied the timing of water injection, as I remember, we're
22 going into these in just a second from..ah..five to nine
23 years, so that would be , like, it'd be in '86. Other
24 companies, I think ARCO presented a study where they delayed
25 the start for like fifteen years. At nine years there is

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1 essentially no -- we got essentially the same benefits from
2 water injection that we got with earlier cases, at fifteen
3 years it was a little less but I don't remember exactly how
4 much less, but it wasn't a great deal less, but it was -- in
5 both cases -- alright, if you wait, one of the things that
6 will happen -- you know -- water injection offers really two
7 benefits as we see it, it's a rate maintenance benefit by --
8 you can maintain the production plateau, whatever that
9 production plateau, 1.5 million barrels a day, we're talking
10 about longer -- it offers some benefits in that regard and
11 also offers some additional recovery benefits, I think we've
12 talked about. If you wait past the point that it -- produc-
13 tion plateau has already dropped off, you've gone in decline
14 portion, then -- and this is the way in previous times,
15 waterfloods were typically implemented. You see a production
16 response, production goes from low to higher..ah..so that's one
17 of the differences that you see with a delayed one is
18 you actually show an increase in production, whereas, if you
19 start before the end of the plateau period it's an extension
20 of the plateau. But the impact on ultimate recovery has been
21 shown to not be very sensitive to timing of the start. Its
22 much more sensitive studies indicate to where the water is
23 injected to getting the most efficiency out of the water you inject.

24 BY: MR. NORGAARD

25 And that -- that is the key point that you're probably going

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1 to get to later, but that is -- you can make a bigger mistake
2 by putting water in the wrong place than you can by waiting
3 too long.

4 BY: MR. SMEDLEY

5 Okay, the next view graph summarizes some of these studies
6 that we've just talked about..ah..these are....

7 BY: MR. MILES

8 Larry can I interject just a second, we had originally planned
9 to break at 5:00, we haven't had any word from the second
10 floor one way or another, so I think what we'll do right now
11 is, I understand a number of people have early evening planes
12 6:30 plans to catch, I think what we'll do is go through
13 until 5:30 and Paul try and finish up with your presentation.
14 Assuming we haven't adjourned by 7:00, we'll come back, any-
15 body who cares to come back, those people from out of town
16 with planes to catch, I don't expect them to come back, I
17 mean you folks have gone above and beyond as has this committee,
18 I think. A number of us are interested in continuing the
19 discussion. To me it's been -- I've learned as much in the
20 last two days as I had in a year, I think, from just
21 the give and take. There are a couple of other people who
22 indicated that they wanted to testify, 7:00 presuming we
23 haven't adjourned..ah..we'll give those folks the opportunity
24 to testify and then again presuming we haven't adjourned, I'd
25 like to just sort of open it up to a general discussion. Ah..

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1 it's a pretty loose way to run an operation, but it -- I
2 think after we adjourn, everyone will be drunk. There won't be
3 too much we can do after that. That's sort of the setup and
4 right now if people have to leave fast at 5:30, I'd certainly
5 like to thank everybody.

6
7 [Discussion re time schedule]
8

9 BY: MR. SMEDLEY

10 This..ah..as I indicated earlier in this hearing, because of
11 the large number of cases that were involved in our sensitivity
12 studies, we ran these cases with our -- with basically a
13 two-dimension -- it's really a three-dimensional model but it
14 can best be classified based on what you've learned in the
15 last couple of days as a cross-sectional model of the
16 reservoir. The field-wide three-dimensional model that we've
17 described and we've shown the history match compared to, was
18 used to verify the cross-sectional runs. But the results
19 we presented at the hearing and that we are presenting here,
20 were run on a cross-sectional model which was proven to be
21 by the three-dimensional model an adequate model for looking
22 at these sensitivities and for predicting the ultimate recovery
23 for Prudhoe Bay. Cases that we looked at with oil offtakes
24
25

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1 ranging from 1.2 to 1.8 million barrels of oil per day showed
2 no significant effect of oil offtake rate on ultimate
3 recovery. These cases that are shown on the chart were run with
4 produced water injection and two billion cubic feet per day of
5 gas pipeline deliveries commencing after five years of pro-
6 duction. The second sensitivities shown investigate the
7 impact of gas pipeline deliveries beginning in 1982, or five
8 years after the start of oil production, compared to delayed
9 deliveries. If we only injected produced water, a 10 year
10 delay in the gas offtake from 1982 to 1992, increase
11 recovery only slightly, from 36.2% to 37.5% of original oil-
12 in-place. Studies show that with appropriate modifications
13 to the reservoir management plan, we can offset this relatively
14 small impact of gas deliveries on oil recovery. One method
15 of offsetting it is with source water injection and it's just
16 shown in the next cases, with source water injection and gas
17 deliveries commencing in 1982, recovery varied for different
18 cases from 39.3 to 40.2% of original oil-in-place, this
19 depended primarily on the level of water injection, this
20 compares to 40% recovery with gas deliveries commencing in
21 1987. So that was comparing '82 versus '87 deliveries. As
22 you're aware, progress has been slow on the proposed gas pipe-
23 line. Consequently, we now believe that 1985 is the earliest
24 likely timing for gas deliveries from Prudhoe Bay. The final
25 results shown on this chart represent the sensitivity of

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1 ultimate oil recovery to various water injection programs.
2 With natural depletion supplemented by produced water injection,
3 a recovery level of about 36% is predicted. This
4 relatively high recovery without source water injection is
5 due to the favorable rock properties that we described earlier
6 from the view graph, which provide for efficient gas cap
7 expansion and gravity drainage over most of the reservoir.
8 The studies show that source water injection commencing in
9 1982 to 1986 with rates varying from 1.7 to 2.5 million
10 barrels per day offer potential to increase recovery to about
11 39% of original oil-in-place, this is the nine year case we
12 were talking about, 1986 starting up. Larger water injection
13 programs that were analyzed commencing in 1982 and 1984
14 resulted in recoveries of about 40%. The studies indicate
15 that ultimate oil recovery is not very sensitive to the
16 timing of injection start-up within reason and within the
17 range as shown. Cases with injection beginning later result
18 in the same recovery if we increase the rate of injection to
19 "catch up" with the earlier injection program. Now, this is
20 because the major benefit of water injection at Prudhoe Bay
21 is improved conformance or sweep efficiency rather than
22 pressure maintenance. Therefore, it's more important to
23 select proper injection locations and volumes than is the
24 timing of injection start-up. Decisions on the proper
25 injection locations in this complex and diverse field will

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1 require substantial performance and testing data as well as
2 detailed studies. As Paul mentioned earlier, there is too
3 much risk of reducing recovery if we were to proceed without
4 sufficient data and we injected water at improper locations
5 so as to impair gravity drainage where it is the most effi-
6 cient recovery process. Indeed, the risk of reducing
7 recovery by improper water injection more than offsets the
8 potentiation risk of deferring the start of injection. With the
9 natural depletion process being very efficient, we believe
10 there is time available to obtain the necessary data and
11 perform the required studies and still be in a position to
12 initiate waterflooding so as to achieve maximum oil recovery
13 benefits. I'll hit briefly the final chart which basically
14 summarizes our conclusions. First, that the Operating Plan
15 studies submitted at the May, 1977 Conservation Commission
16 hearings are still valid. Field performance and testing
17 hasn't significantly changed the outlook that we provided
18 then. Secondly, the oil and gas offtake rates approved by
19 the Oil and Gas Conservation Committee in Conservation Order
20 No. 145 are consistent with achieving maximum economic
21 recovery from the Prudhoe Bay Field. And finally, the
22 ultimate recovery estimates of 40% for oil and 75 to 80% for gas
23 still appear reasonable. However, achieving this recovery will
24 require enormous future investments. These investments must
25 be evaluated and justified individually, considering such

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1 factors as the amount of additional oil to be recovered, the
2 value of the oil , associated operating costs and taxes.
3 Additional production performance and testing data is
4 required before many of these decisions can be finalized. Now,
5 that concludes my prepared testimony and we're aware of your
6 keen interest in waterflooding and what we're doing with
7 regard to studying waterflooding at Prudhoe Bay, so Dave
8 Griffiths of ARCO is now going to give you an update on the
9 progress of our waterflood studies.

10 BY: MR. CHATTERTON

11 Thank you Mr. Chairman. Larry, I appreciate the constraints
12 of time and everything else, but there's one thing that I
13 would like to rap with you on. I realize that you are
14 representing 16 participants here today and that there are
15 16 participants, I presume there's 17 different ideas on
16 everything, as 17th being what you're presenting, the consensus
17 opinion and I appreciate that, but let me follow through a
18 little bit. The thing that has bothered me for a long while
19 is the small -- well, let me put it this way, the expected
20 high natural depletion recoveries of 36% and the small
21 differential between that and full scale of 40% everything.
22 Now, that expected natural depletion, I've been told anyway,
23 was due highly or one of the very major factors and it was
24 gravity drainage. Do we still today, I mean, having watched what's
25 happening, still believe that it's going to be a very overriding

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1 mechanism in the recovery?

2 BY: MR. SMEDLEY

3 Yes sir, we do. And in fact, we have developed some more
4 sophisticated models than the one I described to you today.
5 The impact of the one today was to go back to its earlier
6 developed model. These models, in order to get a very
7 precise match of history, indicate that the shales that we
8 have built in the models are less continuous or the shales
9 are actually less continuous than we built in the models,
10 they indicate that the permeabilities, in order to get a good
11 pressure match, are somewhat higher than was originally
12 anticipated, so the properties as we would analyze them right
13 now today are more favorable for that mechanism than two
14 years ago.

15 BY: MR. CHATTERTON

16 And this, if I may Mr. Chairman, is this in view of the fact
17 that you've showed us a slide today which is the same as you
18 used in '77 that showed the KBKH ratio as being extremely
19 low, you also mentioned that even in '77 you knew about these
20 major shale breaks. Do you still feel you've got an
21 excellent vertical permeability?

22 BY: MR. SMEDLEY

23 That's right. The vertical permeability -- I think we probably
24 concentrated far too much on that small portion of the field
25 over there where the shales are very continuous, gravity

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1 drainage won't be efficient in that area, for sure, where we
2 saw the big pressure sink, but over most all of the field,
3 it's going -- it appears to be very efficient.

4 MR. CHATTERTON

5 Thank you, thank you Mr. Chairman.

6 BY: MR. NORGAARD

7 I think one of the thing is that the..ah.. permeability levels
8 in the reservoirs are very high, so even though you have
9 KBKH that..ah..is less than ideal, you still -- the permea-
10 bility available in the vertical direction is very high.

11 BY: MR. PARR

12 Mr. Smedley, I got into a little thing awhile ago there with
13 you and I thought you sort of made me feel a little better
14 about it, but then your last paragraph, you go back to the
15 statement, comes back to the same point I was raising. You're
16 going to take each one of these things and evaluate it and
17 so forth before you apparently decide to do it. You may not
18 intending to go for 40%. You read the last few
19 lines of your statement you just now read. That's exactly
20 the point that made me raise those questions earlier.
21 You know, I mean is -- are the producers planning to invest
22 this money and shoot for 40% or are they not. The original
23 targets were 40% oil and 75% gas and that was still valid, then
24 you said each one of these additional things have got to be
25 studied and evaluated and I guess costed out, I don't know

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1 what, your own words out of your own statement a few minutes
2 ago which indicates or implies at least, they may not be done,
3 right? And I don't know.

4 BY: MR. SMEDLEY

5 I think both parts of your statement are basically true. We
6 anticipate that they will be done, it is our best estimate
7 that they will be economic. They will be evaluated indepen-
8 dently, they do have to meet our minimum investment criteria,
9 we do not believe that we serve the consumers in -- of the
10 country by making uneconomic investments.

11 BY: MR. PARR

12 What I'm coming back to -- laying down to the sort of bottom
13 line, to use the jargon, there may or may not be an attempt to get out
14 40% if the producers decide that one of these steps you
15 listed is uneconomic, it will probably not be done, therefore
16 those percentages would fall out unless you find some other
17 way to handle it. Is that correct?

18 BY: MR. SMEDLEY

19 All of these are decisions that have to be made, some of them
20 have been made, we indicated we're already proceeding with
21 several of them, we fully anticipate that they will be made
22 based on our best studies today. Those decisions will be made
23 and affirmatively made, but in a grosser sense, I think what
24 you're saying is proper.

25 BY: MR. SHOWALTER

Yea, I would try to answer your question with a question to you

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1 BY: MR. MILES

2 I said no, you're supposed to answer these questions.

3 (indisc. - simultaneous speech)

4 MR. SHOWALTER

5 Do you anticipate that the ferry system schedule in Alaska
6 will be exactly like it is today in 1985 and are you willing
7 to make that decision today or will you examine the budget
8 for the fiscal year '85 when it comes up and decide how
9 much funding you're going to give to the ferry system.

10 I think it's a very similar thing.

11 BY: MR. PARR

12 Well, I don't think so at all, Mr. Showalter. I -- I never
13 expected Exxon or ARCO or BP or anybody else to operate at a
14 loss; nobody would expect me to run my business at a loss.
15 I never -- I never expected that, but the impression was
16 being given to that and that's what I wanted confirmed, either
17 it is or is not, that these things are not firm. They're firm
18 if they're economically feasible for the producer company,
19 is that correct?

20 BY: MR. SMEDLEY

21 That's correct and these other things in that sense are in
22 the same boat as the water injection system. They're all
23 investment decisions.....

24 BY: MR. PARR

25but now we understand one another. These things are all

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1 contemplated if the producers decide they're economically
2 feasible, they will be done.

3 BY: MR. SMEDLEY

4 We believe, based on our best current estimates, that they
5 will prove economically feasible.

6 BY: MR. PARR

7 I said but that's your -- that's an estimate, there's no
8 guarantee of any of that.

9 BY: MR. SMEDLEY

10 That's right.

11 BY: MR. PARR

12 That's all I wanted to get clear.

13 BY: MR. NORGAARD

14 Let me just say one thing that I think is consistent and
15 compatible with this, until the owner companies have
16 authorized the expenditures for whatever lies in the future,
17 and that could be the next well in Prudhoe Bay, there's
18 nobody that could say it will happen. Once the expenditure
19 has been authorized, we can say it will happen. We can look
20 at the plan and say that is what we think will happen. I
21 think we can go a step further. I think I can say that the
22 decisions will be easy, but I don't think there's anyone who
23 can say until the major companies and a proper vote has been
24 taken that this will be done. It does take the senior manage-
25 ment of our companies to say that it's a proper expenditure before

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7 ON
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1 we can make it, but we believe in everything that we've done,
2 and I'm speaking for ARCO right now, that the decisions are
3 easy, they're not tough decisions. Now does that help?

4 BY: MR. PARR

5 I think so, thank you. I think we understand where each other
6 is coming from now and it is all clearer now that this is
7 not -- anything guaranteed at this point.

8 BY: MR. GRIFFITHS

9 Thank you, Mr. Chairman. My testimony will last about 20
10 minutes if I go through it rather hurriedly, so with your
11 permission, I'll take off. If there are any questions why
12 somebody (indisc.)

13 BY: MR. MILES

14 Before you start so you don't get interrupted, if anybody
15 has to take off to catch a plane, I know we said we'd stop
16 at 5:30, it's almost 5:30 now. Anybody besides you, Mr.
17 Griffiths? Okay, let's go.

18 BY: MR. GRIFFITHS

19 Members of the House Resources Committee, ladies and gentlemen,
20 my name is David Griffiths. I received a Bachelor of Science
21 degree in Petroleum Engineering from the University of Texas
22 in 1958, and was employed by Atlantic Richfield as an engineer-
23 ing trainee. Following three years of military service, I
24 rejoined ARCO where I have had a number of reservoir produc-
25 tion engineering assignments. Since moving to Alaska in 1974,
I have been directly associated with North Slope activities.

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1 For the past two years I have been a member of the Prudhoe
2 Bay Unit Planning Subcommittee, which has had the responsi-
3 bility of coordinating the waterflood studies which have
4 been conducted in the Unit. During the next few minutes, I
5 would like to discuss the progress of the waterflood studies
6 that have been underway during the past several years. I
7 will briefly reflect on the work that has been done to date
8 and describe the current status of the waterflood project.
9 Following this, I will outline the future waterflood project
10 plans as they are now envisioned. Between 1969 and 1974,
11 several waterflood feasibility studies were undertaken by
12 ARCO, Exxon and Sohio. The studies led to these conclusions,
13 first a waterflood system for Prudhoe Bay is mechanically
14 feasible; second, the most probable source of water is the
15 Beaufort Sea; and third, field performance history is needed
16 to properly design the system. Work done between 1974 and
17 1976 established eighteen engineering studies that would
18 need to be undertaken prior to completing the conceptual
19 design of a waterflood system. Such studies would include
20 analysis of water source, freeze problems, soils and perma-
21 frost; ice; weather, materials selection, water treatment,
22 and more general project interface studies such as environ-
23 mental and permitting requirements, project planning, and
24 cost estimating. While many of these study areas were common
25 to many waterfloods, some were unique to Prudhoe Bay.

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1 Following the formation of the Unit, owners have maintained
2 an aggressive program to resolve questions regarding the
3 viability of a waterflood. This effort has proceeded on
4 two fronts; one, improving our knowledge of the reservoir
5 and secondly, developing a waterflood design. As has been
6 mentioned, reservoir studies have recognized the potential
7 benefits of returning produced water to the reservoir and of
8 supplementing the produced water with source water for some
9 time. Estimates of additional oil recovery ranged from
10 four to seven percent of the oil-in-place. We recognized
11 that production history would be needed to verify the need,
12 locations, and volumes of waterflood. We identified areas
13 of engineering interpretation, such as fact efficiency,
14 stratification in the reservoir, and injection of well
15 capacity as important factors affecting the expected benefits
16 resulting from waterflooding. In addition, early in the
17 reservoir study period we recognized the effects of geolo-
18 gical factors such as faults, the heavy oil/tar mat, shale
19 continuity on the selection of flood location, volumes and
20 flood performance. As an example, shale continuity is perhaps
21 the most important geological factor affecting choice of
22 recovery mechanism and it's the most discussed here today.
23 The two most efficient recovery mechanisms available, gravity
24 drainage and waterflooding, are each capable of higher than
25 average recoveries in particular areas of the field. Normally,

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1 gravity drainage works better in thick oil columns which have
2 no continuous shale barriers blocking oil movement, while
3 waterflooding works better where the oil column is broken up
4 by continuous shales into several isolated layers. It is
5 vitally important to identify areas where gravity segrega-
6 tion is most effective prior to injecting water. If water
7 is injected into areas where the shales are discontinuous,
8 the waterflood recovery will be poor and the more effective
9 natural recovery mechanism will be eliminated. On the other
10 hand, if the shales are continuous, gravity segregation will
11 be less efficient than waterflooding. However, reservoir
12 studies show that even in these areas the ultimate recovery
13 is effectively unchanged with a minor delay in initiation of
14 waterflooding. Consequently, it is far more important to know
15 where to waterflood than when to waterflood. Since shale
16 continuity is such an important factor, a group composed of....

17 BY: MR. MILES

18 How can they determine -- if that's true, how can they determine
19 for example like we've heard earlier in Alberta, where
20 waterflood prior to a field going into production.

21 BY: MR. SMEDLEY

22 Let me try and take a shot at that. Ah.. frequently, that's
23 done -- you don't have the same situation like the one that
24 I'm most familiar with because it's an Exxon field, is J
25 Field in Florida which other than Prudhoe is the most

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1 significant discovery in recent times. We -- decided to
2 waterflood J very, very early and started water injection
3 essentially at the start of production. It was -- it had
4 no possibility of good efficient natural depletion mechanism.
5 It was..ah..I don't want to get into the technical terms,
6 it's natural recovery would have been very low, nothing like
7 in the order of 30's% like we have at Prudhoe, it would have
8 been like less than 20% and so, there wasn't this option to
9 trade off -- you know -- to -- maybe, the natural
10 mechanism may be more efficient in some areas at least than
11 an induced mechanism.

12 BY: MR. MILES

13 Even -- almost setting the recovery level aside, if it's more
14 important to know where to sink that hole as opposed to when,
15 don't you have to have some kind of a production history,
16 I mean (indisc - simultaneous speech) We keep hearing that
17 everything has to be done based on production history..ah..
18 and this seems to fly in the face of that..ah..so, I guess
19 I don't understand, even if the -- even if your -- you know --
20 the best hopes without waterflooding are only 20%, it seems like,
21 at least from what we've heard, you'd have to know the
22 dynamics of the field prior to -- prior to sinking a water-
23 flood well.

24 BY: MR. SMEDLEY

25 It depends -- its -- every reservoir is so different and so

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1 unique..ah..if it's purely a pressure maintenance thing,
2 if your putting the water in, many times the water is just
3 injected out in the aquifer out in the natural water
4 bearing part of the reservoir, not even within the oil part
5 of the reservoir. Okay? Just purely for pressure main-
6 tenance because the reservoir would not do well if you
7 didn't inject it, like at J. The pressure -- in the first
8 year of production at J, for instance, here we are talking
9 about a 200 psi pressure drop in two years, at J the
10 pressure drop would have been thousands of pounds in this
11 period of time. An order of magnitude difference. So,
12 the need was obvious, the injection -- so the injection
13 was started Ah..and it was done -- the reservoir
14 properties were such that you didn't have this concern of
15 -- you know -- messing up an efficient natural mechanism
16 in some parts of the reservoir by injecting in others.
17 You had -- you had a very poor natural mechanism you
18 couldn't foul it up any worse than it was -- you know.
19 Face it, you aren't going to get hardly anything if you
20 didn't do something.

21 BY: MR. NORGAARD

22 Let me offer a comment on that, too, if I may, Mr. Chairman.
23 I think we can go to a very close Alaska scene, the Trading
24 Bay unit. There is an utter saturated reservoir; it has
25 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

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1 in the laboratory analyze it and see what the expectations
2 would be if you waterflooded and you can determine very
3 quickly and very early that you have a natural and logical
4 candidate to waterflood. The waterflood is initiated in
5 Trading Bay unit, I believe, within three years. It was --
6 you know -- as fast as they could physically get equipment.
7 And, in that you just have a single mechanic, just a single
8 mechanism, it's solution gravity -- it's solution to drive
9 system where you just have rapid fluid expansion. Very
10 simple. You can look at it, you can analyze it and you've
11 got, probably 20 other reservoirs that you can hone in on
12 immediately that are similar, and you just need to get
13 some laboratory data of the rock itself and the fluids
14 themselves and you can go. Canadian reservoirs could be
15 that same kind of thing. In Prudhoe you've got a very
16 complex field. You've got several mechanics working
17 simultaneously, you need to determine how they are working,
18 how they're interrelating, how the -- and the locations
19 of the interrelation. So you do need some time to look, I
20 would speculate also that the fields in Canada are generally
21 very small and they have a sister or a cousin that are pretty
22 close by. You know -- there's a lot of oil fields in Canada
23 and there's only one Prudhoe -- you know -- it's very
24 difficult to find a sister or cousin, but there's an awful lot of
25 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

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1 that's exsands (ph) -- exsands well that works this way, so
2 we'll do it. I think, I'd turn to Dr. vanPoolen for a
3 probably a better explanation than that.

4 BY: MR. MILES

5 Do you care to comment?

6 BY: DR. DOSCHER

7 The story is if you have a gravity drainage field, so
8 in part, or in the most part, now, if you started injecting
9 water in that gravity drainage, you may ruin the gravity
10 drainage next. So we want to find out where there is no
11 gravity drainage where the shales are and not just the
12 shales from the cores and the logs but also the shales from
13 the production history. That's why we need some production
14 history. It's rather obvious we're going to go, I mean,
15 that the industry will start flooding the eastern part of
16 the field now that we have confirmed that shale breaks
17 are accurate. That's why we have to have history. Where
18 in all the other stages are correct. If you have a small
19 field and no good drive mechanism, you start injecting water
20 and it doesn't matter where you put it in, you're not ruining
21 anything. In this case, you have a chance of ruining a good mechanism
22 by waterflooding so you want to be selective in where you put it.

23 BY: MR. GRIFFITHS

24 Since shale continuity is such an important factor, a group
25 composed of ten geologists from five companies spent thousands

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1 of man hours verifying and updating shale correlations and
2 making predictions as to their continuity between wells and
3 in undrilled areas in the field. This work has indicated
4 that the shales are less continuous than previously predicted,
5 which emphasizes the need to proceed with caution. Further
6 improvement in the shale description will result from
7 continued drilling and history matching the production
8 performance of the field and wells with reservoir models.
9 Also, the vast number of pressure buildups and the inter-
10 ference test data are providing insight into shale continuity
11 and reservoir depletion mechanisms. A reservoir engineering
12 study group from the Unit Owner companies has been working
13 steadily to narrow the uncertainties related to this project.
14 The group has identified seven potential waterflood areas in
15 the field and has undertaken specific reservoir studies in all
16 of the major areas. The key to verifying the benefits to be
17 derived from waterflooding is the analysis of the production
18 and test data that is constantly being collected. Highly
19 sophisticated "state-of-the-art" reservoir models have been
20 developed and we are now comparing the detailed performance
21 history with the model predictions. By next year the owners
22 expect to have the knowledge upon which to base initial
23 waterflood decisions. To enable an early evaluation of the
24 many reservoir and mechanical factors which can affect the
25 success of a large scale waterflood, the Unit Owners have

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1 implemented two pilot water injectivity tests in the Sadlerochit
2 reservoir. One of the tests, located in the Western
3 Operating Area near Gathering Center No. 3, was completed
4 recently and the data that has been obtained is being analyzed.
5 The other test, located in the Eastern Operating Area near
6 Flow Station No. 1, is underway and will soon continue --
7 and will continue for about nine more months. The pilot
8 tests have been designed to evaluate reservoir parameters
9 such as injection pressures and injection capacity in the
10 wells, the efficiency of water in displacing oil in the
11 reservoir, aquifer properties, and the impact of water quality
12 on injectivity. The mechanical factors under investigation
13 include an evaluation of two artificial lift systems, poten-
14 tial corrosion, scaling and freezing problems, and general
15 design parameters. In addition, a valuable benefit from the
16 tests is an opportunity to gain operating experience with a
17 North Slope waterflood. Although very costly, so far about
18 \$33 million, the tests are providing extremely worthwhile
19 data. Soon after unitization, the owners formed a Waterflood
20 Task Force. The Task Force, consisting of sixteen full-time
21 engineers from several owner companies, was charged to accom-
22 plish the design studies previously mentioned and develop a
23 conceptual design for a waterflood project. The normal
24 sequence of events in the design and implementation of a
25 waterflood is first to define the benefits to be derived from

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1 the flood and then specify design parameters, such as flood
2 locations, volumes, pressure, quality, etc., and then design
3 a system to meet these requirements. Because of the time
4 required to fabricate and construct a major facility such as
5 this at Prudhoe Bay, we have carried out the facility design
6 and the reservoir engineering studies concurrently. As a
7 result, the design was developed to accommodate a range of
8 potential flood volumes. As is the case with most projects
9 of this magnitude, a wide range of alternative concepts was
10 developed for practically every facility in the system. In
11 July, 1978, we retained Bechtel Inc., an engineering contrac-
12 tor, to fully evaluate these alternatives. An average of
13 fifty contractor personnel have been employed in the con-
14 ceptual design studies. Early this summer, we developed a
15 conceptual waterflood design which will accommodate the range
16 of potential injection requirements, as I mentioned. The
17 slide before you shows a layout of the waterflood system.
18 The conceptual design envisions the Beaufort Sea as the
19 water source. The seawater would be treated in a facility
20 located near the end of the west dock (indisc). From there
21 the low pressure lines would carry the treated water to two
22 water injection plants, one located in the east area near
23 Flow Station No. 1 and one in the west area near Gathering
24 Center 1. From the plants, high pressure injection
25 water would be transported to appropriate drill sites and

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1 drill pads for injection. Although we still need to resolve
2 several design questions during the next phase of the
3 engineering, which incidentally is already underway, the
4 project is mechanically feasible and environmentally sound.
5 Prudhoe Bay owners recently submitted applications to the
6 Corps of Engineers for major permits required to install
7 waterflood facilities. Supporting these applications is a
8 two-volume document entitled, Prudhoe Bay Unit Waterflood
9 Project Overview, and I have copies of those here.
10 Volume 1 is the engineering overview and it is a pretty
11 complete description of the Prudhoe Bay conceptual design
12 as it stands now. Volume 2 is an environmental overview that s
13 prepared by a consultant, Woodward Clyde, and Mr. Chairman
14 I'd like to leave copies with you for the record.

15 BY: MR. ROGERS

16 May I ask, is that -- are you going to have to file a
17 environmental impact statement in addition - in addition to
18 that for waterflooding plant?

19 BY: MR. GRIFFITHS

20 We expect that an environmental impact statement will probably
21 be required. Ah..the determining agency will be the Corps of
22 Engineers.

23 BY: MR. ROGERS

24 And..ah..are -- do you have any problem with water injection
25 in the winter up there?

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1 BY: MR. GRIFFITHS

2 Some of those 18 studies that I've mentioned were addressed
3 to that very question and we think -- well, we're quite
4 certain that we can operate through the winter months.

5 BY: MR. ROGERS

6 Well, maybe you're going to get into this later, but I under-
7 stand the North Slope Borough has an ordinance that could
8 effect -- it effects a lot of the activities up there, is
9 that going to effect the waterflooding operation do you think?

10 BY: MR. GRIFFITHS

11 We really don't know, that ordinance has not been finalized,
12 to my knowledge.

13 BY: MR. NORGAARD

14 Certainly it is a concern to us. We are working with the
15 borough and..ah..you know -- we intend to work with the
16 borough in every way we can, but that is a very great concern
17 to us that..ah..they -- they are moving forward on "CZM"
18 ordinances and what is written right now would be very
19 difficult to operate and work with, and we're optimistic
20 that we will be able to work with them to come up with some-
21 thing that makes sense, but that's a great concern.

22 BY: MR. ROGERS

23 Am I hearing you say then that the ordinance could prohibit
24 you from waterflooding?

25 BY: MR. NORGAARD

We will have to get the borough's concurrence on what we

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1 propose to do, yes, as well as the Corps of Engineers,
2 as well as the State of Alaska, as well as, I believe, the
3 citizens of Alaska. I'm not sure that there's anybody's
4 approval we don't need.

5 BY: MR. CHATTERTON

6 (Indisc - simultaneous speech) I told you that I would like
7 an opportunity to ask a facetious question, but I guess it's
8 been partially answered, so I'll rephrase it. Have you or
9 do you plan to send a courtesy copy to the North Slope
10 Borough, to the Coastal Zone Management..ah..group, also?

11 BY: MR. NORGAARD

12 We have met with just about all agencies that have any
13 involvement and met with the borough at least twice before
14 submitting the application to them. We've visited with --
15 explained what we were planning on doing and have gotten
16 any suggestions that they have had at that point in time and
17 we certainly would intend to follow to all these agencies
18 with the permits, but it does have to go through the
19 Corps of Engineers and then they become the lead agency and
20 they do their thing. We are continually following and work-
21 ing with all agencies to see if we can't assist them whatever
22 way we can and answer questions that they must have, certainly
23 they will have some questions. Thank you for the question,
24 Mr. Chatterton.

25 BY: MR. CHATTERTON

Thank you, Mr. Chairman. You're welcome.

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1 BY: MR. NORGAARD

2 I was suppose to say that when I got a chance and I forgot.

3 BY: MR. GRIFFITHS

4 As we have pointed out before that the waterflood implemen-
5 tation schedule envisions a 1984 startup and this slide
6 shows the events needed to get to startup in 1984. A major
7 decision will be required on the part of the Unit Owners in
8 mid-1980 in order to achieve a 1984 startup. To meet this
9 objective, we must complete the preliminary engineering
10 design and sufficiently resolve the reservoir uncertainties
11 in order to verify the recovery benefits by that time. Also,
12 I know that you can appreciate our need to have permits in
13 hand prior to any major commitment of funds to the project.
14 If the decision is to proceed with the waterflood, long
15 lead-time equipment orders will be placed and the final
16 design of the system will commence about mid-1980. Fabrica-
17 tion will begin in mid-1981. Sealifts then will occur in
18 1982 and 1983 and construction of the facilities on the North
19 Slope would take place between 1982 and 1984.

20 BY: MR. MILES

21 Excuse me Dave, I guess I'm missing something in the time
22 frame. I thought the water injection, natural water injec-
23 tion was going to begin in '81, that's when you got up to
24 100 thousand barrels of..ah..produced water.

25 BY: MR. GRIFFITHS

That's right.

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1 BY: MR. MILES

2 Well how can -- if you got -- how can you do the engineering
3 in '80

4 BY: MR. GRIFFITHS

5 I'm sorry, I failed to point that out that this is the
6 schedule for the major waterflood, the source waterflood.

7 BY: MR. MILES

8 So those are really two independent operations, completely
9 independent of each other.

10 BY: MR. GRIFFITHS

11 They're independent in that the time frame is different and the
12 source of water is different. Eventually, of course, those
13 two systems will have to be -- will have to come together,
14 not physically, but from a injection sense and become part
15 of one major waterflood system.

16 BY: MR. MILES

17 I see, but the produced water injection, or the source water
18 injection doesn't depend on what happens from the produced
19 water injection, when you pump the 100 thousand barrels back in.

20 BY: MR. SMEDLEY

21 Not at least in the first increment because the basic
22 decisions will have been made for the first part of the source
23 water system before the -- before you'll have that information.

24 BY: MR. NORGAARD

25 I think, we're tied in with what both Dr. vanPoolen and

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1 Doscher indicated was that some of the information we can
2 get through laboratory studies and with the injection
3 programs we currently have, the two programs we have now that
4 one could call the tests or one could call pilot,
5 depending how you felt that day, and we are anticipating
6 getting all the information required, to go ahead and make
7 the decisions in 1980 from those two pieces, so we do not
8 need this source water injection to make the decision in 1980.

9 BY: MR. MILES

10 Well, you -- okay, you don't need the information from the
11 produced water injection to make the source water injection
12 decision in 1980, is that correct?

13 BY: MR. NORGAARD

14 Yes.

15 BY: MR. MILES

16 I see, okay, thank you.

17 BY: MR. ROGERS

18 Could you tell me what you're expecting for a construction
19 work force up north.

20 BY: MR. SMEDLEY

21 Our current estimate is about 1600.

22 BY: MR. ROGERS

23 And a maintenance work force after you've completed construc-
24 tion.

25

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1 BY: MR. SMEDLEY

2 Oh, in the order of 100 people to operate a system depending
3 on how large the system turns out to be.

4 BY: MR. GRIFFITHS

5 I'm sure you will recognize most of the areas constituting
6 the project schedule are inter-related and delay in finali-
7 zing one segment could impact the overall schedule. I would
8 like to briefly discuss each of these major segments and
9 identify those areas that potentially could delay the
10 implementation of the waterflood. The reservoir studies,
11 of course we have discussed at great length, I don't think I
12 need to expand on those, except to say we do have a high
13 degree of confidence that the reservoir studies will develop
14 the necessary design parameters and recovery benefits on
15 time. The major permit applications have recently been
16 submitted, and consequently, it will be several months before
17 a firm assessment of the permit timing can be made. Since
18 the potential exists for considerable slippage in this area,
19 permitting could become a critical factor in achieving a
20 1984 startup. The preliminary engineering design phase is an
21 in-depth review of the system that has been developed in the
22 conceptual design. At the completion of this phase, all
23 major equipment for a system to handle a finite volume of
24 water at specified locations and pressures will be identified.
25 This is a major engineering effort. Final design is the

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1 phase in which equipment and piping layouts, valve and
2 vessel design, control system layouts, and construction
3 drawings are prepared. Again, for a project of this magni-
4 tude, this will be a massive effort involving about 1000
5 owner company and contractor engineering personnel. The
6 long lead items include structural steel, turbine-driven
7 pumps, water treatment equipment, and other specialized
8 items associated with the flood. We have forecasted delivery
9 times based on our previous experience with such equipment
10 and forecasts of market conditions and their availability.
11 Unforeseen changes in availability of these items could
12 cause delayed deliveries and if these deliveries are severe,
13 the delays are severe, it could delay a sealift. In the
14 fabrication stage, the equipment previously mentioned is
15 assembled in modules for sealift to Prudhoe Bay. The
16 principle variables affecting this schedule are material
17 deliveries and manpower availability. The critical factor
18 here is that minor slippage could cause a delay of one year
19 in the sealift. Sealifts are the vital link between the
20 North Slope and the Lower 48. Due to the size of the modules
21 no other transportation system is feasible. The critical
22 factors affecting the success of a sealift are the ice condi-
23 tions in the Beaufort Sea and the ability to unload barges
24 once they arrive at Prudhoe Bay. The ice factor is beyond
25 our control, of course, but we have been able to achieve at

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1 least a partially successful sealift even under the worst
2 conditions experienced during the past five years. Our
3 planning calls for the waterflood equipment to be sealifted
4 at the same time the other major facilities that Larry
5 mentioned, are programmed for the Prudhoe Bay Field. The
6 total forecasted requirements will tax the existing dock
7 facilities, and our ability to achieve that goal would be
8 highly questionable if it were not for the West Dock and
9 causeway. With this facility, we can develop the offloading
10 capacity. The North Slope construction schedule is based on
11 several years of experience. The primary factor that would
12 affect this schedule is an unforeseen lack of construction
13 manpower. The commissioning and startup of the waterflood
14 system will, in some respects, be a unique experience and as
15 such, it could encounter minor delays. By 1984, however, we
16 will have had a produced water injection system in operation
17 for three years which, along with the injectivity tests, will
18 develop valuable operating experience. In general, we feel
19 we have a realistic implementation schedule and are confident
20 it can be achieved. On the other hand, we feel there is
21 very little chance that the schedule can be accelerated.
22 The one area that will have the most impact on the schedule
23 is the timely receipt of the necessary permits. The permit
24 schedule carries the greatest chance of -- for slippage and
25 could easily delay the project a year or more.

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1 BY: MR. ROGERS

2 Yea, what State permits are required?

3 BY: MR. GRIFFITHS

4 There's a..ah..a permit required that you operate from the
5 Oil and Gas Commission, there are permits that are required
6 from the Dept. of Environmental Conservation, there are
7 permits required from..ah.. the land department I don't
8 recall -- Fish and Game (indisc) land use permits..ah.. affecting
9 gravel and what have you and the Fish and Game Department,
10 that's correct.

11 BY: MR. ROGERS

12 Do you think it would be -- would be helpful in this -- in
13 the critical permitting area if the State were to appoint a
14 permit coordinator or some -- some sort -- equivalent to the
15 pipeline coordinator that we've got on board.

16 BY: MR. NORGAARD

17 Are you speaking for just waterflood or total?

18 BY: MR. ROGERS

19 Well, for the waterflood.

20 BY: MR. NORGAARD

21 Well, as you understood there's a lot of other things that
22 are very critical too, besides just the waterflood, we got a
23 lot of other facilities that will be going and they're
24 equally critical, because almost of them require permits of
25 some kind all the way through. Really, our permit dealings

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1 with the State during the X period of time have been --
2 we've been very satisfied. We are, I believe, working very
3 well together. Our greatest concern that we have at this
4 point in time, is the multitude of different -- bodies that we
5 deal with, the North Slope Borough, the Corps of Engineers
6 and the State, and being able to coordinate those things
7 together and seeing that one doesn't have objective A and one
8 doesn't have objective B and they conflict. Who's going to
9 resolve that conflict. That's our biggest concern right now,
10 it isn't so much dealing with the State or dealing with the
11 Corps.

12 BY: MR. ROGERS

13 Do the three governments have any -- any kind of..ah..group
14 -- the same way the operators have a group planning for this--
15 do the three governments...

16 BY: MR. NORGAARD

17 Not at this time, the Corps has indicated a desire and will-
18 ingness to work with the State, so that their systems are
19 compatible in -- would simplify the process. I'm really
20 not familiar enough with the borough's intentions to speak
21 to that. Somebody here may be, I'm not. That's a new phase
22 that we're just getting into -- you know -- and that's going
23 to be one that we'll have to crawl before we can walk, I
24 guess.

25 BY: MR. ROGERS

Could you keep the committee posted on, particularly the

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1 State's efforts and if there are any problems along that.

2 BY: MR. NORGAARD

3 We would love too, thank you.

4 BY: MR. ROGERS

5 On manpower requirements, are there any specialized forms of
6 training required that we might want to -- that the State
7 might want to be pushing in the next couple of years to make
8 sure we had the right kind of manpower available for you.

9 BY: MR. GRIFFITHS

10 No, the craft manpower that will be required to install the
11 waterflood will be the same disciplines that have been avail-
12 able in the past to install the existing facilities and the
13 same people are going to be....

14 BY: MR. ROGERS

15 The same ones are primarily non-residents which is why I was
16 asking the question. Is it primarily plumbers and steamfitters
17 dependent work that would....

18 BY: MR. GRIFFITHS

19 I think it crosses a whole range of crafts and manpower,
20 electricians, plumbers, welders, pipelayers, just about every
21 -- every profession is up there.

22 BY: MR. NORGAARD

23 I don't believe that you'll single anyone out, you see, that's
24 the one you concentrate on.

25 BY: MR. ROGERS

Do you know well enough which ones you're going to need so

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1 we can try to assist at all in making them available.

2 BY: MR. GRIFFITHS

3 Our studies, as far as the waterflood are concerned, have not
4 gone into that detail.

5 BY: MR. NORGAARD

6 Let us worry that a bit because it's a broader question than
7 waterflood question. We do have lots of other facilities
8 going. And, we have looked at what the requirements will be
9 on the slope (indisc.), and we just have to look at that
10 and talk to our construction people.

11 BY: MR. ROGERS

12 'Cause you're going to be going at the same time as some gas-
13 line construction, perhaps it's quite possible that a lot
14 of these things will be going on concurrently and that could
15 create some -- a demand that we couldn't fill with residents
16 unless we knew about it in the next year or so, so we could
17 gear up some training programs.

18 BY: MR. NORGAARD

19 We appreciate the desire.

20 BY: MR. ROGERS

21 If there is any way that you can let us know during the next
22 legislative session, I think it would be rather helpful.

23 BY: MR. NORGAARD

24 We will be happy to work with that .
25

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1 BY: MR. MILES

2 Dave, you indicated a passle full of permits that you have
3 to get from Fish and Game, the Land Use Planning and
4 Environmental Conservation and who knows, did you say in your
5 presentation what the status of those, have those all been
6 applied for, have they been filled out or what -- for the
7 waterflooding project?

8 BY: MR. GRIFFITHS

9 So far we have made applications the Corps of Engineers
10 for about six or seven permits.

11 BY: MR. MILES

12 You haven't done any State applications and permits.

13 BY: MR. GRIFFITHS

14 We have not applied for State permits for the waterflood as
15 yet. That's going to be one of the next steps.

16 BY: MR. MILES

17 Okay, if this is one of the most significant problems and it
18 seems like everybody's been saying, all along, you planned
19 to go into this full scale waterflooding project, why didn't
20 you start sooner?

21 BY: MR. GRIFFITHS

22 Well, in order to submit a permit application we had to have
23 a conceptual design. The Corps of Engineers or
24 whoever will permit a specific system, they won't just permit
25 waterflooding -- you know -- across the board. We had to

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1 develop a conceptual design and document it and also to
2 prepare an environmental overview for that system, prior to
3 submitting permits. Earlier this summer, we did complete
4 that conceptual design and then moved right ahead with the
5 documentation of it and the environmental aspect of it. As
6 soon as those were completed the permits went in and we
7 anticipate the longest lead permit will be from the Corps of Engineers.

8 BY: MR. MILES

9 I see. You couldn't simultaneously apply for all of these,
10 is that right?

11 BY: MR. GRIFFITHS

12 No sir.

13 BY: MR. MILES

14 You got to -- do you have to get something back now from the
15 Corps of Engineers?

16 BY: MR. GRIFFITHS

17 We have to get an okay, our first look at it, yea, it looks
18 like its a hell of a deal.

19 BY: MR. MILES

20 Do they -- say something like that before you can apply to
21 the Dept. of Environmental and Conservation. I just don't
22 know what the -- you know -- what the....

23 BY: MR. GRIFFITHS

24 No, we do not have to get something back fro the Corps of
25 Engineers before we make..ah..subsequent applications.

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1 Matter of fact, we have other applications in the process
2 right now, that have not been submitted but they're being
3 prepared. Ah..the first act from the Corps of Engineers,
4 first official act, will be whether or not the Corps of
5 Engineers declares this a significant federal action.

6 BY: MR. MILES

7 Are they slower than the State is that why you went there
8 first?

9 BY: MR. NORGAARD

10 Dave let me see if I -- let me see if I can answer your
11 question. We obviously, as everybody, there's only so many
12 things you can do at one time and so we take the most
13 critical element first and the most critical element was the
14 permit from the Corps of Engineers and we will go ahead and
15 follow that -- you know -- as quickly as we can get the data
16 together in the form that's desired and required and move
17 forward on the permits. But, we don't see any of the other
18 ones as being the critical length. The one that's in
19 is the critical length. We may have guessed wrong, we don't
20 think we have. We see that as being the most critical and
21 we got that in as fast as we could. Now, we'll take the
22 same data that we had in that application and put it in a
23 different format so it satisfies the other permit requirements.
24 But, we have visited with all the people already, got their
25 input so we know what their concerns and desires and requiremen

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1 are and, therefore, in that context we have got a jump on
2 the game, if you will, and that was it -- we were able then
3 to pick the most critical and move forward on it.

4 MR. CHATTERTON

5 Thank you, Mr. Chairman. Dave, you made sort of an innocuous
6 statement about the westside dock and causeway. I've been
7 told that the Corps of Engineers' permit, and I don't know
8 whether it was issued through the unit or to ARCO, had a
9 requirement that they remove at a certain time, and I've
10 further been told that there are those that are pressuring
11 the Corps to have you meet that requirement. Now, apparently
12 this west dock and causeway is an integral part of your
13 waterflooding, -- have I been told right is the first question
14 and where's that issue stand now?

15 BY: MR. GRIFFITHS

16 I don't know really if
17 somebody is being pressured for us to take the dock out. I
18 think the initial permit did not stipulate we would have to
19 take the dock out, it stipulated we would have to do environ-
20 mental studies which we have done each year to assess the
21 impact of the dock being there and I suppose we would be
22 subject to take -- having to take the dock out if there was an
23 environmental impact shown. So far, there has not been any
24 environmental impact shown.

25 BY: MR. CHATTERTON

As far as you're concerned.

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1 BY: MR. NORGAARD

2 The permit did -- you'd have the stipulation
3 that we could be required to taking the dock out at a point
4 in time. It did not say that we had to, but it has the
5 stipulation that we can be required.

6 BY: MR. CHATTERTON

7 Thank you, thank you, Mr. Chairman.

8 BY: MR. MILES

9 (indisc - simultaneous speech) Mr. Griffiths did you conclude
10 your statement?

11 BY: MR. GRIFFITHS

12 I just have one brief summary, Mr. Chairman.

13 BY: MR. MILES

14 I thought you had concluded. Joe do you want to go now or...

15 BY: MR. McKINNON

16 Well, I'm not sure -- just one question. One of the things
17 you're doing to increase recovery is to double up spacing of
18 wells to..ah..150 acres and that increases it by 4% or 5%.
19 What would increasing it to 80 acres make?

20 BY: MR. SMEDLEY

21 That's as we indicated in the May, '77 testimony. The
22 way you go about developing is you drill and we were then
23 drilling on 320 acres spacing, and we've since been drilling
24 on 160 acres spacing. We will continue to look at that and
25 as we drill and see performance of these wells -- you know --

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1 reservoir, to drill wells on 80 acres spacing, and, if so, we
2 would go to the Oil and Gas Conservation Commission and ask
3 for permission to do so. Right now, the Pool Rules specify
4 160 acre spacing, so we would have to get permission to
5 drill on denser spacing.
6

7 BY: MR. NORGAARD

8 ARCO did testify at the May, '77 hearing that by drilling, and
9 I forget how many 80 acre wells, but there were quite a number,
10 that recovery would be increased by 1%, either 1 or 1.2.
11 Chat could check me out, but it's in that range. The point
12 is that you can increase oil recovery, obviously, by adding
13 wells, but it's a diminishing return to go from 320 to 160
14 got 4%, to go from 160 to 80, in certain areas, got 1%. Ah..
15 so, and I forget who it was yesterday suggested that you could
16 mine the Prudhoe Bay, I guess it was Hoyle, but you could
17 mine Prudhoe Bay and 100%. And that's -- the closer you're
18 making wells, that's the closer you are to mining the
19 reservoir.

20 BY: MR. CHATTERTON

21 May I make a statement for the record that with this dis-
22 cussion that we've had and seeing as how my name was men-
23 tioned, I have a distinct conflict of interest and I'd like
24 that known. (Laughter)

25 BY: MR. MILES

Go ahead, Mr. Griffiths, if you'd like to conclude.

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1 BY: MR. GRIFFITHS

2 In summary, the Prudhoe Bay Owners have proceeded in an
3 aggressive and orderly manner to verify the feasibility of a
4 waterflood in the Sadlerochit Reservoir. This course
5 follows very closely the program outlined in the Unit Owners'
6 presentations before the Oil and Gas Conservation Committee
7 during the hearings in May, 1977. Reservoir studies and
8 design studies have progressed concurrently. Injectivity
9 tests have been designed and implemented, and analysis is
10 progressing with the production data -- production history
11 and test data obtained to date. As a result of many years of
12 reservoir studies and the analysis of field production, we
13 feel we are developing an excellent understanding of the
14 Prudhoe Bay reservoir and its future performance. We intend
15 to continue our extensive efforts to build on this foundation.
16 During the past two years alone, the Prudhoe Bay Unit Owners
17 have invested over 40 million dollars in engineering studies
18 and special tests designed to reduce the risks associated
19 with a source waterflood. The Waterflood Task Force has
20 developed a conceptual design based on a Beaufort Sea water
21 source and the Task Force is proceeding into the next phase
22 of engineering. Permit applications have been submitted to
23 the Corps of Engineers. Permitting could become the critical
24 factor in meeting a 1984 startup of the project. The Unit
25 Owners plan to be in a position to make the decision to

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1 proceed with a source waterflood project by mid-1980 if the
2 permits are in hand and the project is determined to be
3 economically viable. Mr. Chairman, that concludes my testimony.
4 I think Mr. Norgaard has some concluding remarks .

5 BY: MR. PARR

6 I have one question and you probably mentioned this and I
7 missed it. Have your tests indicated that this Beaufort
8 Sea water is suitable for the purpose or is it -- are you
9 going to have to build a conditioning plant of some sort or
10 what?

11 BY: MR. GRIFFITHS

12 Yes, we will have to build a treating plant. Now the
13 Beaufort Sea water, based on the tests that we have run so far
14 and those tests started back in 1976, indicates that the
15 Beaufort Sea is a very good quality water, but still it will
16 require some treatment and heating and that facility is the
17 one that will be located out at the end of the west dock.

18 BY: MR. PARR

19 Thank you.

20 BY: MR. MILES

21 Are there other questions? Mr. Norgaard, would you conclude?

22 BY: MR. NORGAARD

23 It's been long and I'm going to make a very short concluding
24 statement. Maybe, that will be unique for me. First off,
25 I think that Prudhoe is unique in one respect and it's come

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1 out repeatedly and that is the money, technical expertise
2 and manpower that have been dedicated to that field to learn
3 as much as we can and to manage it as properly as we can for
4 all parties concerned. I think it's unique in the annals of
5 oil fields and considering the reservoir we're dealing with,
6 it's appropriate, and I think the oil companies will continue
7 to treat it as such. Secondly, the plan is a sound plan,
8 and we believe it should be followed. We believe we said that
9 very clearly. We see it actually maximizing the amount of
10 oil and gas to be recovered from the Prudhoe Bay Field and
11 I think oil and gas is important. I know Dr. Doscher did not
12 feel that 1.5 trillion feet of gas was significant. That
13 equates to over 200 million barrels of oil, so I guess I
14 feel it is equivalent. And, in my opinion, it definitely is
15 something that will not be seen. When you burn it, you burn
16 it and that's that. Ah..thirdly, the plan, I believe again,
17 is prudent for both the owner companies and the State of Alaska
18 and, in this regard, I believe our interests are essentially
19 identical. And the reason for that is the reservoir is a kind
20 of reservoir where the decisions are not borderline decisions.
21 They are broad, big decisions in the different economics
22 that exist between us, which will always exist between us;
23 it's not a critical element. And, lastly, we have worked
24 with this Oil and Gas Conservation Commission in the past,
25 we certainly intend to work with them fully in the future

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1 and...ah...we expect to share our ideas and thoughts and our
2 information with them as frequently and as openly as
3 they desire and that's the end of my -- and we thank you
4 again for the opportunity to be here today and, hopefully,
5 we've shed some light on what we're doing and what it means
6 to you and to the State of Alaska. Thank you.

7 BY: MR. MILES

8 So, great gentlemen...ah...thank you very, very much -- it's
9 been thoroughly enlightening to me and I think to other
10 members of the Committee. We know you have gone well out
11 of your way to come up here and put your presentation together,
12 and it has been enlightening and most appreciated. Also, I'd
13 like to thank you, Ken, for what you did in organizing the
14 effort. It's most appreciated. It's now 6:15. I think
15 we'll back up our voluntary evening session at 7:15 and give
16 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 Kansas 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 accelerated 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 attracts 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 plausible 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.

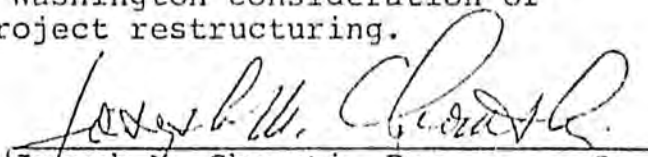
We do believe, however, that there are several steps the State can take which will at least minimize whatever delay is inherent in the process and which may assist in protecting the State's interest if and when Congressional consideration of federal guarantees is initiated. These steps include:

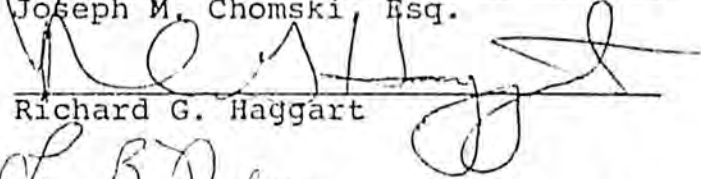
1. A concerted and coordinated effort, both by the Legislature and the State Administration, to provide a current information flow on positive State actions taken with respect to the project. This would include regulatory, environmental and right-of-way actions, even of a minor nature. This process would 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.

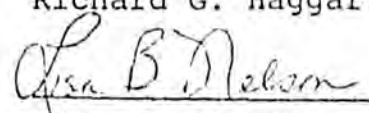
2. As we indicated above, we do not believe direct lobbying in Washington would be of significant benefit in speeding federal assistance for the project. It is not so clear, however, that private and frank discussions with senior Northwest officials regarding the need to request federal assistance from Congress in order to speed the project might not be productive. To the extent that such discussions may have already occurred, at least informally, it is logical that they would have involved senior members of the State Administration.

3. To the extent that Northwest may in the end attempt to lay the blame for the failure of private financing at the door of other parties, it may become increasingly important for the State to take some steps to protect itself by positive action on its own program of financial assistance. We believe general approaches such as those suggested by Arlon Tussing in his memorandum to Senator Mike Colletta and Representative Bill Miles of May 14, 1979 should be carefully considered. In our view, even the most minimal and contingent sort of commitment to the project could have important value to the State as the question of financial assistance is considered in Washington. The very real possibility must be considered that Congress may demand a "pound of flesh" in return for federal financing -- and it is possible that the pound of flesh would be exacted at the wellhead and/or in the pipeline rates of return to operating companies. If the State is on the record as having taken at least minimal steps across the board to support the project, it will be able to come to the proceedings in Washington with clean hands; alternatively, and absent evidence of such State action, the Congressional response could be to take action to penalize those parties, including the State, which it perceives as having failed to adequately support the project. Such an approach would almost certainly be guised as a "proconsumer" step (i.e., lowering or taxing the wellhead value or reducing pipeline tariffs in some fashion) and would undoubtedly be termed an appropriate price to exact in return for guarantees provided by the nation's taxpayers. The current proposal to impose an excess profits tax on Alaska oil, despite the fact that this oil only recently reached previous federal price ceilings, is illustrative of the ability of Congress to impose new and contradictory conditions on energy production, if it wishes.

We recognize the great difficulty that the State and the Legislature have in attempting to move forward on this project, given the great confusion and disarray that currently exists in Washington. Nonetheless, we believe taking at least minimal steps and publicizing those positive actions to the Congress and the federal bureaucracy could provide the State with some protection against possible punitive Congressional action at the time federal guarantees are considered. Such a program will improve, although by no means guarantee, the prospects for equitable treatment of the State of Alaska in future Washington consideration of federal loan guarantees and project restructuring.


Joseph M. Chomski, Esq.


Richard G. Haggart


Lisa B. Nelson

AGO 532459

Joint Gas Pipeline Committee
Alaska State Legislature

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CO-CHAIRMAN

REP. BILL MILES
CO-CHAIRMAN

SEN. FRANK FERGUSON

REP. C.V. CHATTERTON

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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-fulfilling prophecy, Rhett suggested, with a need for federal guarantees created by people saying there is a need for federal guarantees.

In regard to possible state financing, Rhett responded, "We'd love to see it." The proposed state revenue bonds are "probably pretty well expected in the financial community." It would, said Rhett, "put a shock through the system" if the bonds are not issued. However, he added, no federal/congressional action has been taken on the change in the IRS Section 103 code change necessary for the state bonds to be issued. The request for a change in the code "has never been asked. It really has not been formally presented within the federal government." A state equity investment would be a "much tougher" issue, Rhett said, noting that equity investments must be "prudent" and involve major philosophical questions.

"Any financial occurring at this time is a conditional form of financing...You're not dead certain whether you're buying a pig in a poke," said Rhett.

REPORT ON INFORMAL MEETING OF THE
JOINT GAS PIPELINE COMMITTEE - 2

PROJECT TIMELINE --Preliminary financing must be arranged by December 31, 1979, Rhett stated. "I feel that by December 31 this year, it's either going to be positive or we've got real problems and we're going to slip another year." Asked if Alaska financial commitment was also necessary by December 31, Rhett replied, "What we're talking about this fall is not that tight a package." Alaska, he indicated, would not lose out by making a decision about state participation in project financing at a later date.

Other project dates, as outlined by Rhett, are as follows:

Preliminary financing by December 31, 1979.

Northwest application for certification by June, 1980.

Federal Energy Regulatory Commission processing of the certification application will take one year, with an additional five months allowed for litigation, bring completion of the certification process to October, 1981.

Design on the Alaska segment will be seventy percent done in 1982. Until then, Rhett said, no completely good financing estimate for the project will be available. By that time Northwest will have spent an estimated \$400 million.

FEDERAL FINANCING -- In response to questions about the federal government's reluctance to participate in project financing, Rhett said that consideration of federal guarantees raises both philosophical and monetary problems. "You start guaranteeing these bonds for natural gas, what does that do -- downgrade every other federal bond for natural gas? Does this mean every major project has to have federal guarantees?"

TECHNICAL ISSUES --The proximity issue (how close the project will be constructed to the existing Alyeska oil pipeline) will ultimately be resolved, Rhett said. "There are some knotty issues there-- technical and legal, particularly liability." By federal law, Alyeska has unlimited liability for the oil pipeline.

OTHER ITEMS -- Rhett regarded as "very controversial" reports indicating that early gas withdrawals may damage ultimate oil recovery at Prudhoe Bay. In regard to the Canadian segment, Rhett reaffirmed the federal support for that project, although he admitted "some stagnation" in Canadian progress. Promising an open exchange of information, Rhett plans to headquarter in D.C. until after the Canadian 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.



Official Business

Alaska State Legislature

House of Representatives

Committee on Resources

Pouch V
State Capitol
Juneau, Alaska 99811

August 2, 1979

To: Members of the House Resources Committee
Members of the House Interim Committee on Oil & Gas
Leasing Policy

From: Mary Halloran
Research Analyst

Attached are copies of the questions sent to the Alaska Oil & Gas Conservation Commission, Mr. Hank Van Poolen 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 Poolen 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. VanPoolen 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?

QUESTIONS - 2

6. Have you also analyzed other secondary recovery methods besides waterflooding? If so, what conclusions have you reached? Has CO₂ 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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FEB 11 1980

Senator Mike Colletta
Alaska Senate

Dear Mike,

Here are the materials Van Poolen 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 Poolen 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 F+



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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

TMD/jak
Enclosure

AGO 532467 +

ANALYSIS OF THE RESULTS OF THE NUMERICAL SIMULATION
OF THE
SADLEROCHIT RESERVOIR PRUDHOE BAY FIELD

February 3, 1980

Prepared for
The JOINT GAS PIPELINE COMMITTEE of the STATE OF ALASKA

AGO 532468



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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.

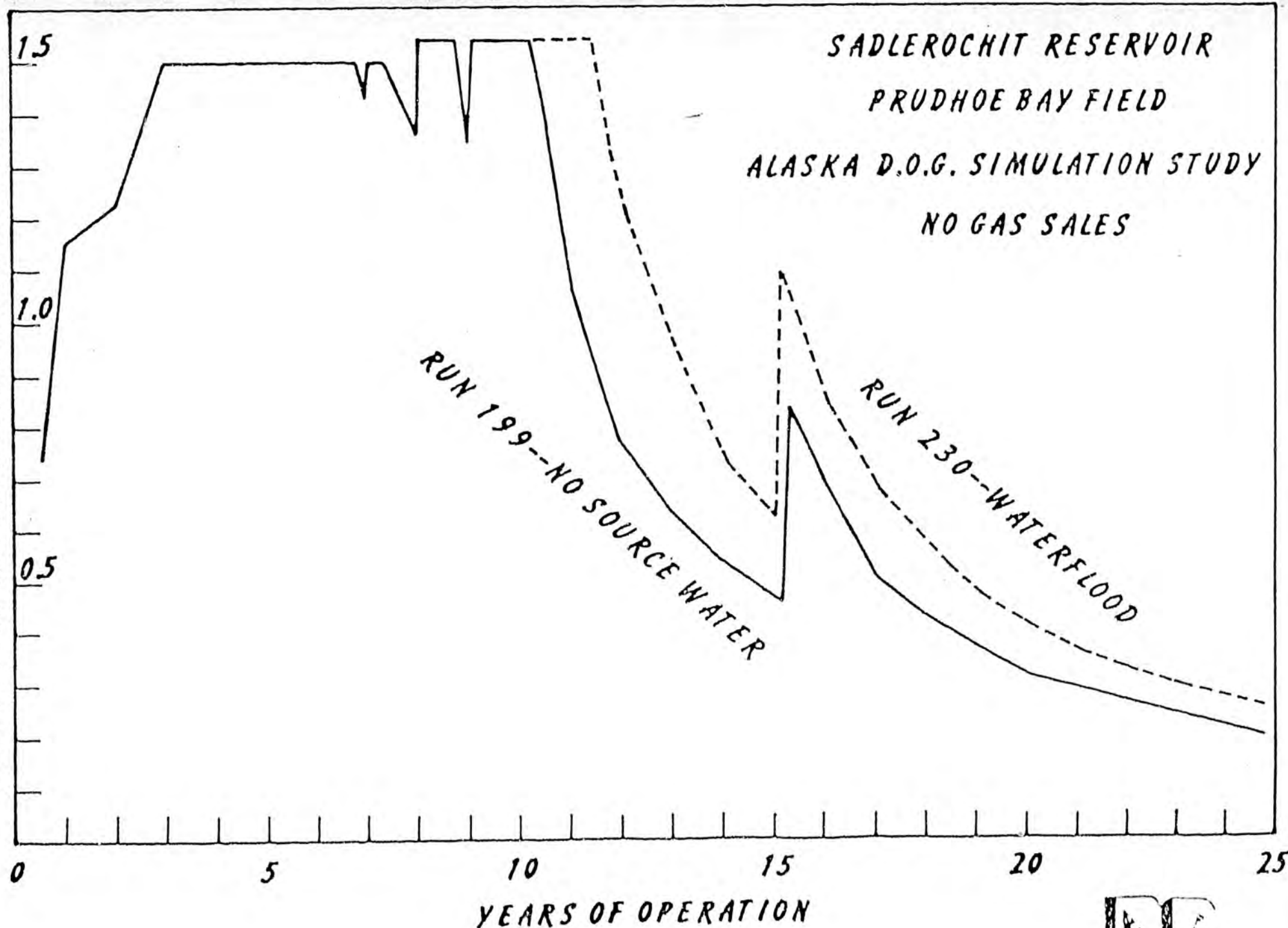
AGO 532469



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PRODUCTION RATE, MILLION BARRELS PER DAY

AGD 532470



11255 05 7 PRODUCTION RATE, MILLION BARRELS PER DAY 532471

SADLEROGCHIT RESERVOIR

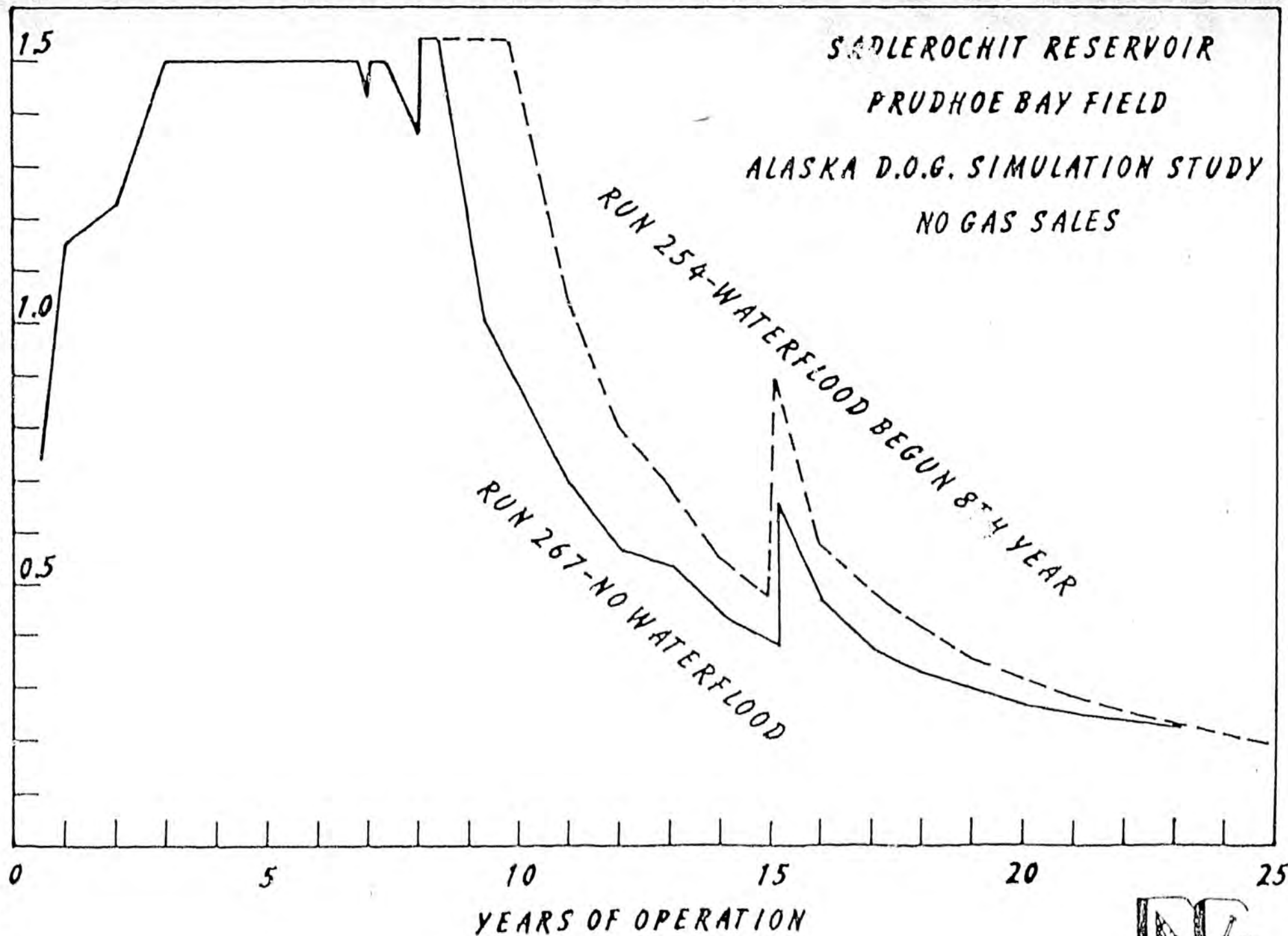
PRUDHOE BAY FIELD

ALASKA D.O.G. SIMULATION STUDY

NO GAS SALES

RUN 254-WATERFLOOD BEGUN 8TH YEAR

RUN 267-NO WATERFLOOD



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.)

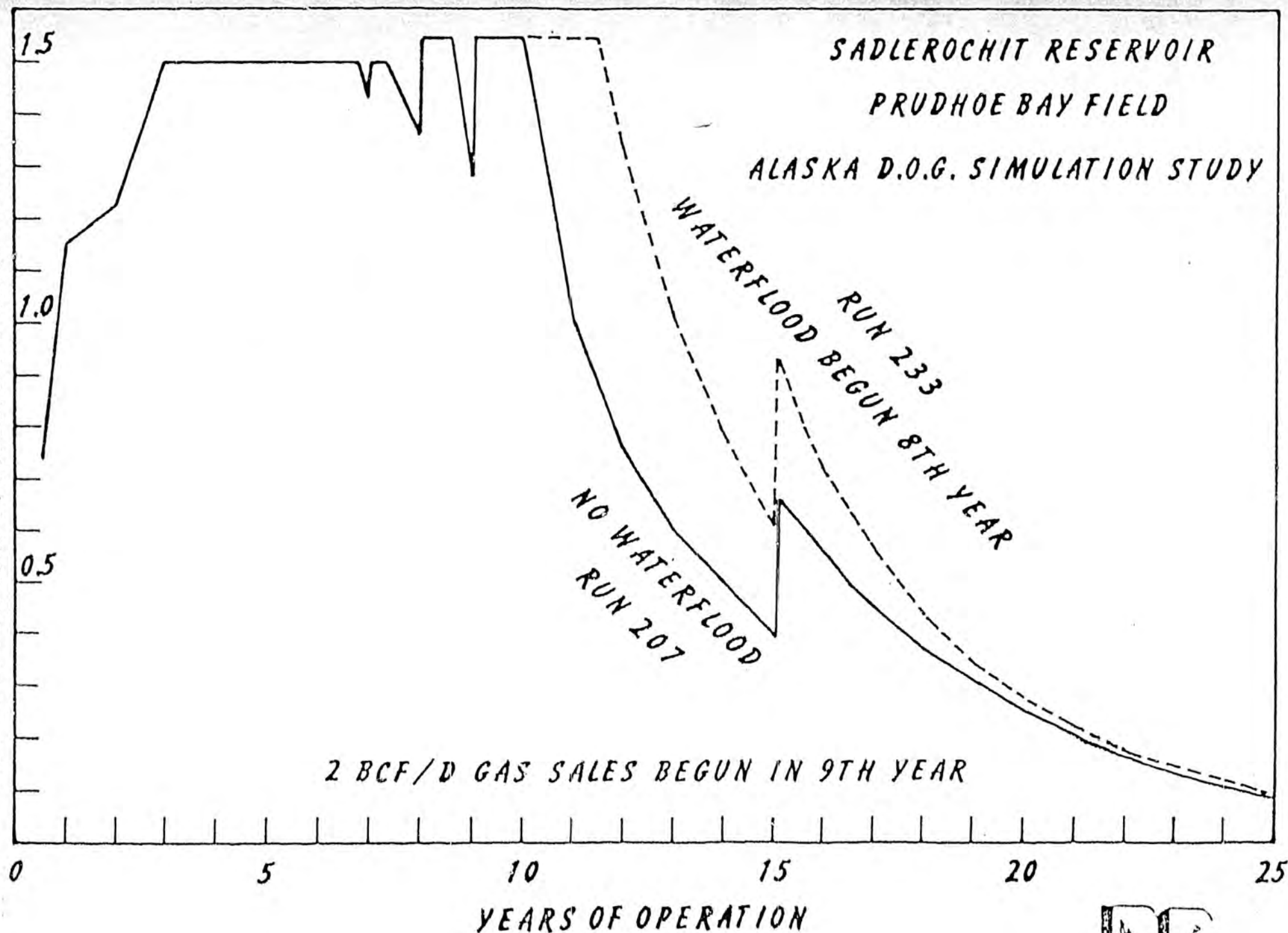


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AGO 532472

ELSES AGO 532473

PRODUCTION RATE, MILLION BARRELS PER DAY



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

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PRODUCTION RATE, MILLION BARRELS PER DAY

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SADLEROCHIT RESERVOIR

PRUDHOE BAY FIELD

ALASKA D.O.G. SIMULATION STUDY

NO WATERFLOOD, NO GAS SALES

EFFECT OF WELL FACTORS

RUN 267-LESS FAVORABLE FACTORS

RUN 199-FAVORABLE FACTORS

RECOMPLETIONS 8 153 189 21

102

YEARS OF OPERATION



IV. OVERALL CONCLUSIONS AND RECOMMENDATIONS

THE NUMERICAL SIMULATION OF THE SADLEROGHIT 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 SADLEROGHIT 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 as 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%.



Representative Bill Miles
Juneau, Alaska
February 6, 1980
Page 2.

Considering the probability that water flood facilities would be being installed and some new drilling being continued, there could be significant problems merely in the deployment of the expertise required for conducting the necessary work-over operations.

Theremore 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.

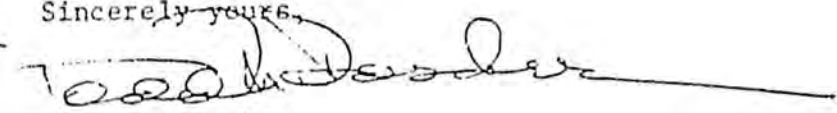
Finally, there is the question of the well factors, viz., the relative permeability functions assigned to the well bore. Unfortunately the well function can not be predicted in any absolute sense. It is one of the parameters that are "tuned-in" to achieve the history match between actual and simulated 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 significant 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 water-flooding (rather than peripheral), and somewhat decreased offtake rates may have significant effects.

The model is now ready for extended-in-time history matching, and the exploration of such issues as noted in the preceding paragraph.

Sincerely yours,


Todd M. Doscher.

OBJECTIVES

evaluate oil recovery

with or without source water injection

with or without gas sales

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+

BOUNDARY CONDITION

max. field take off _____ 1.5 million bbls/day

gas sales _____ 2.0 billion cf/day

max. source water injection _____ 2.0 million bbls/day

max. resvr. press. 3900 psi during source water inj.

start of source water injection _____ mid 1984

start of gas sales _____ mid 1985

field cut off rate _____ 100,000 bbls/day

produced water to be reinjected _____ mid 1981

artificial lift

low pressure gathering system

original hydrocarbons in place

stock tank oil _____ 20.5 billion bbls

solution gas _____ 14.9 trillion cf

gas cap gas _____ 23.4 trillion cf

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

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

EFFECT OF GAS SALES ON OIL RECOVERY

(A oil recovery) - (C oil recovery) $\stackrel{*}{=}$ 40.8 - 35.9 $\stackrel{*}{=}$ 4.9%
without source water cases

(B oil recovery) - (D oil recovery) $\stackrel{*}{=}$ 46.1 - 45.4 $\stackrel{*}{=}$ 0.7%
with source water cases

or

0.14 billion bbls of oil

* without optimum recompletion

CONCLUSIONS

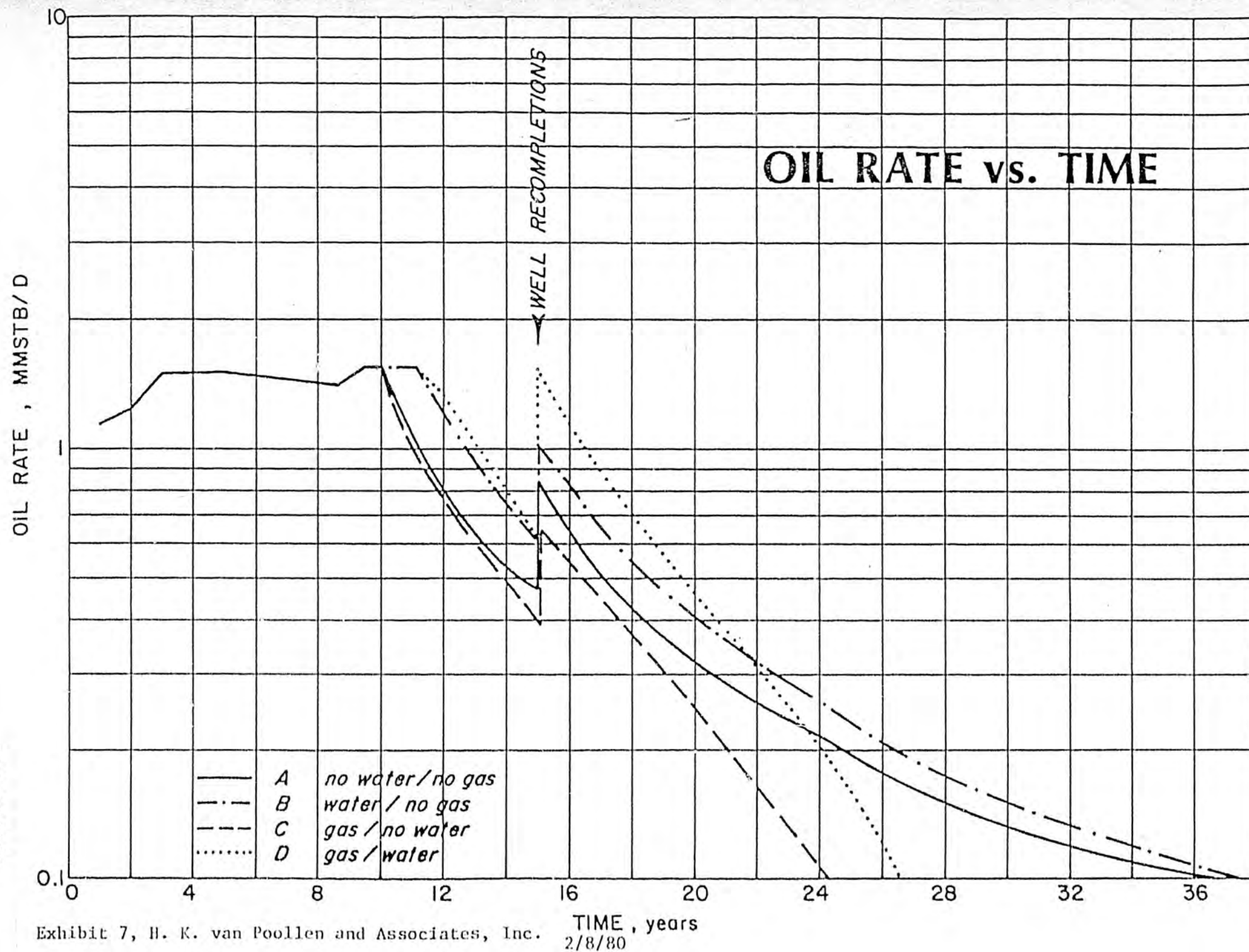
A source water injection program:

- 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**

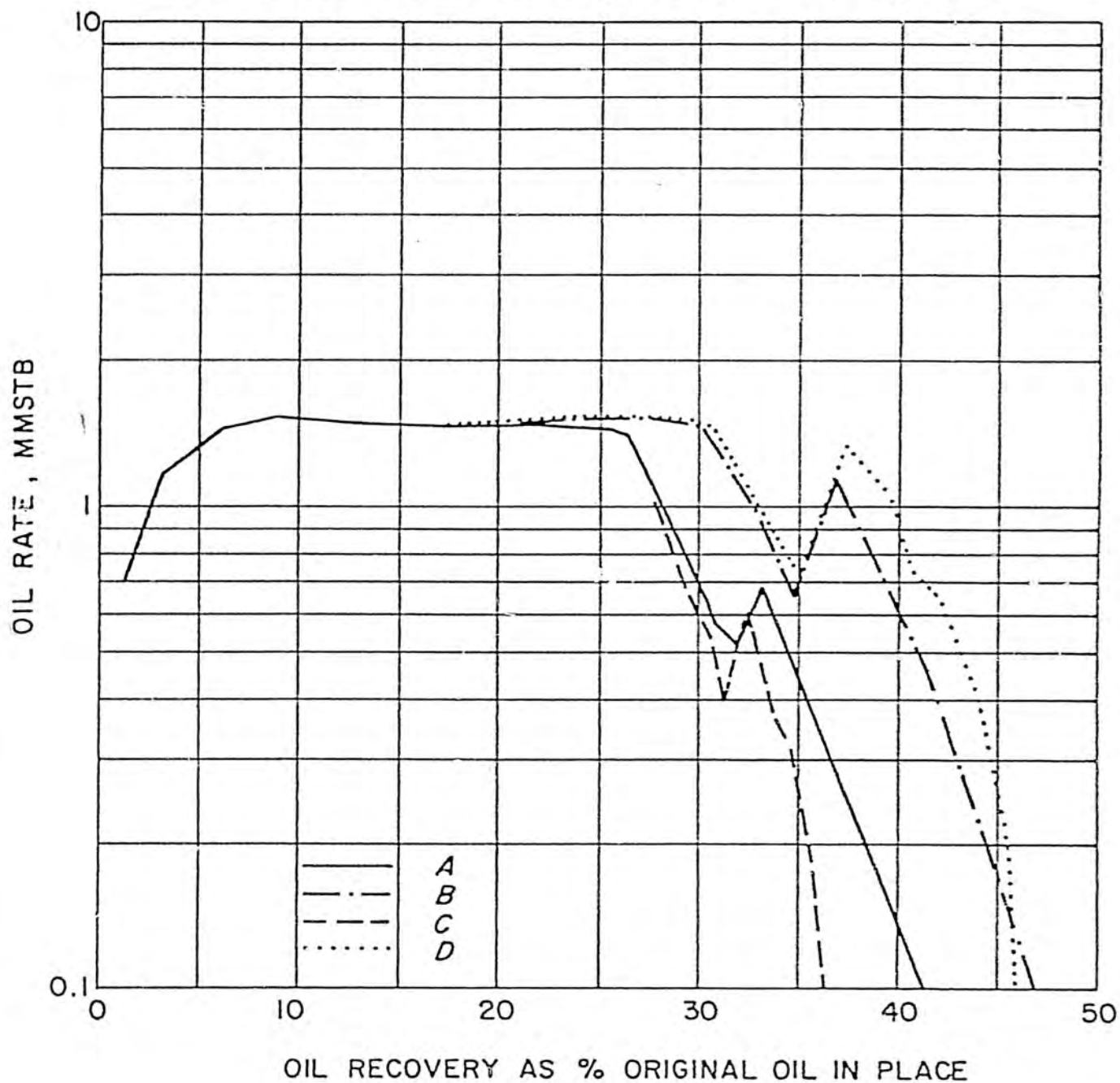
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OIL RATE vs. RECOVERY



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.

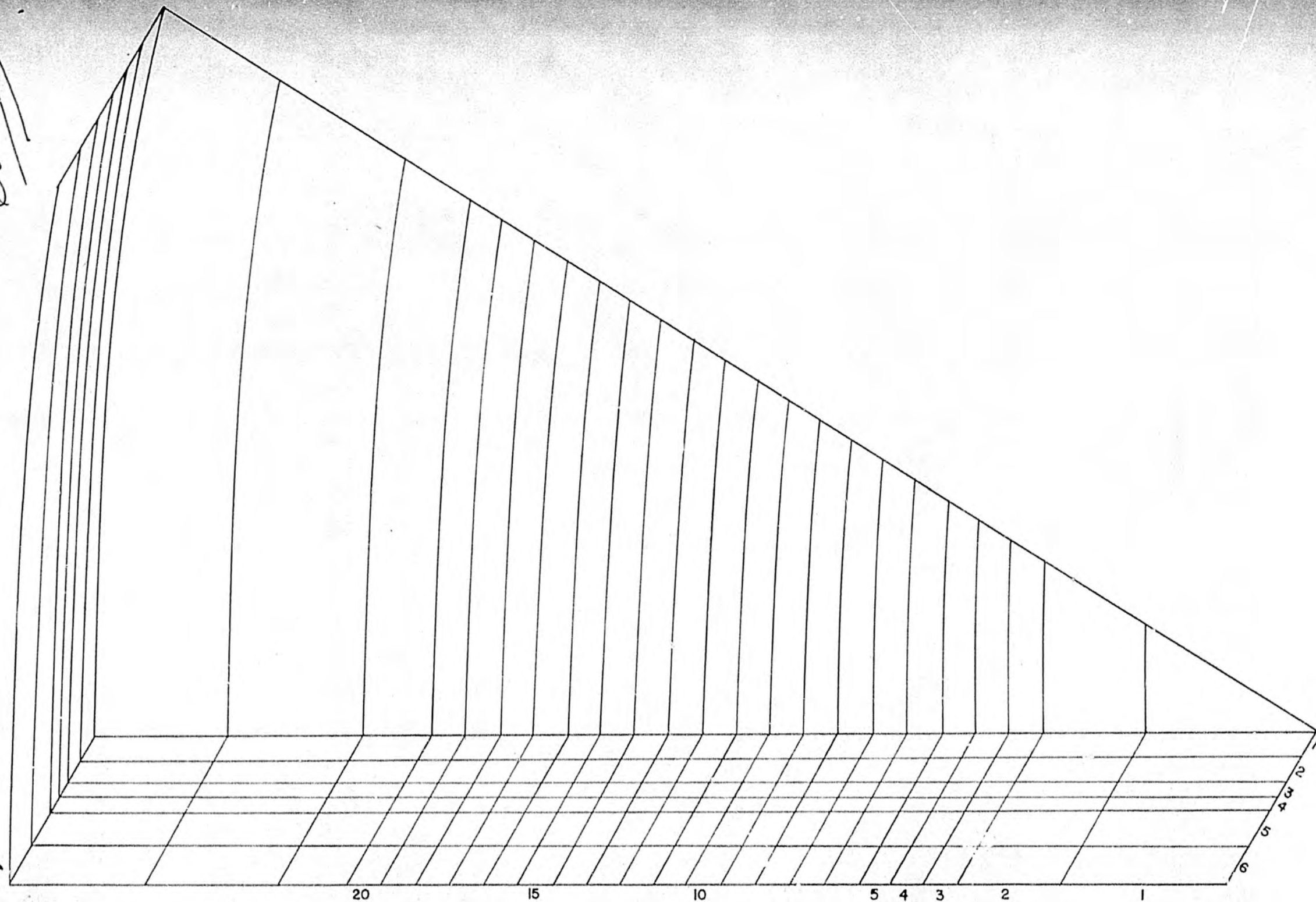
THE INTERACTION OF FORCES BETWEEN ROCK AND FLUIDS ARE GIVEN BY THE FOLLOWING SATURATION DEPENDENT FUNCTIONS:

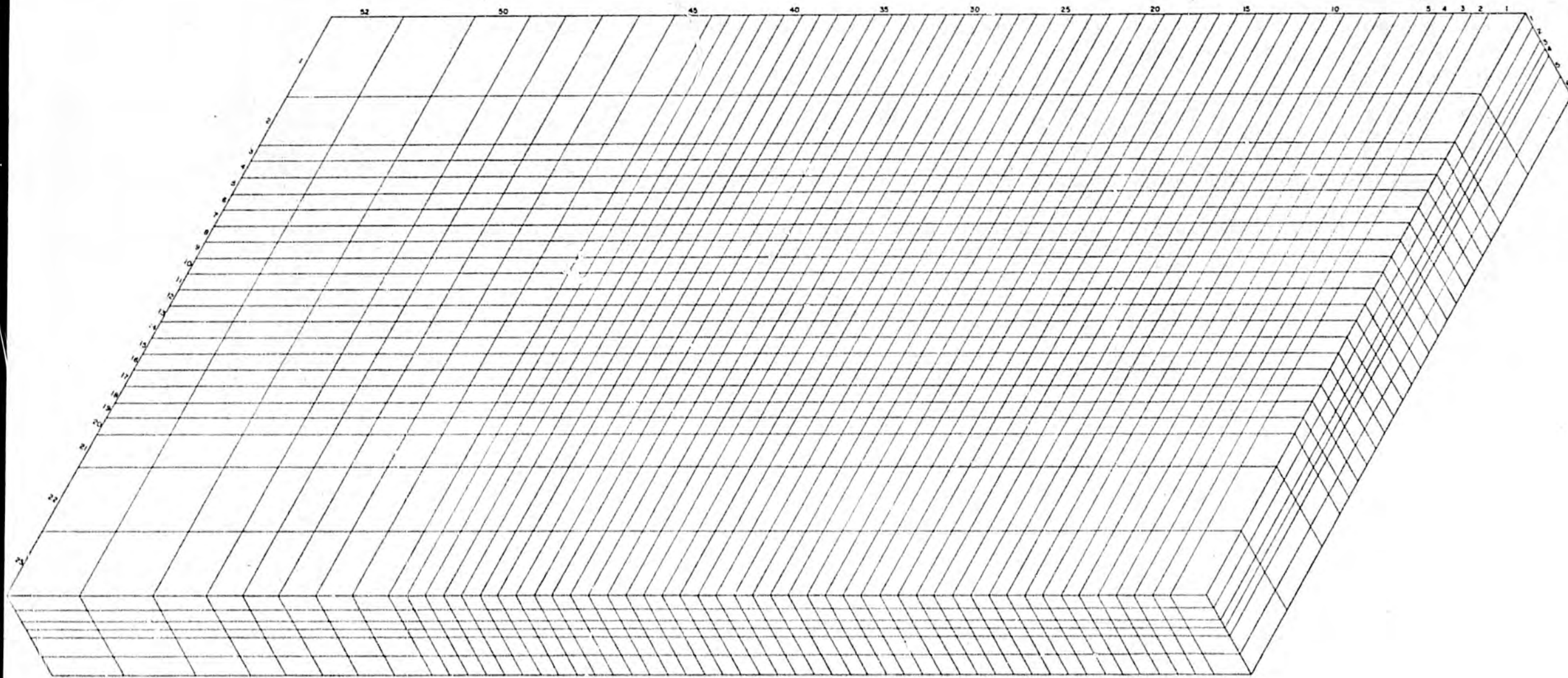
RELATIVE OIL PERMEABILITY.
RELATIVE WATER PERMEABILITY.
RELATIVE GAS PERMEABILITY.
CAPILLARY PRESSURE BETWEEN OIL AND WATER.
CAPILLARY PRESSURE BETWEEN GAS AND OIL.

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



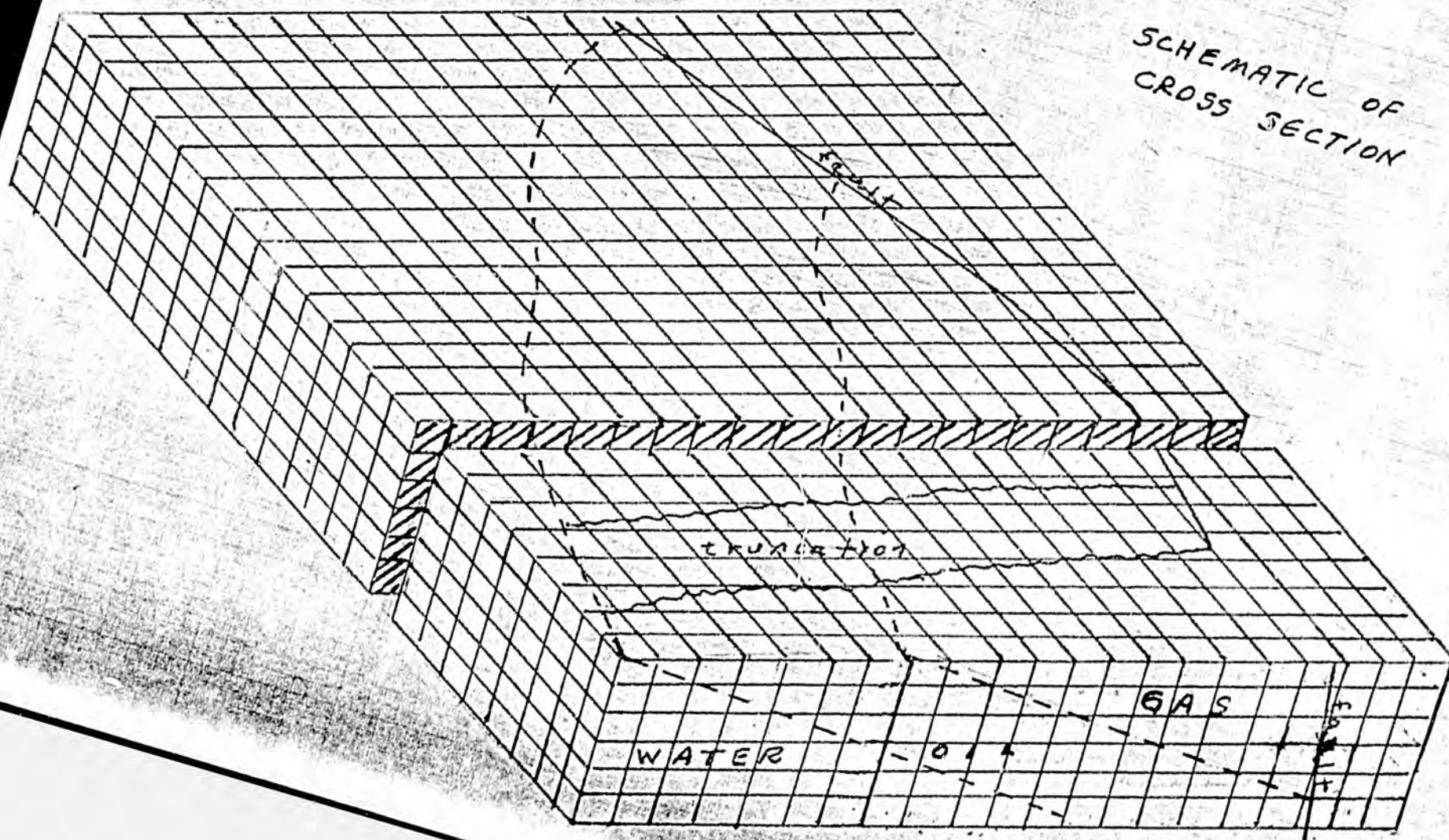


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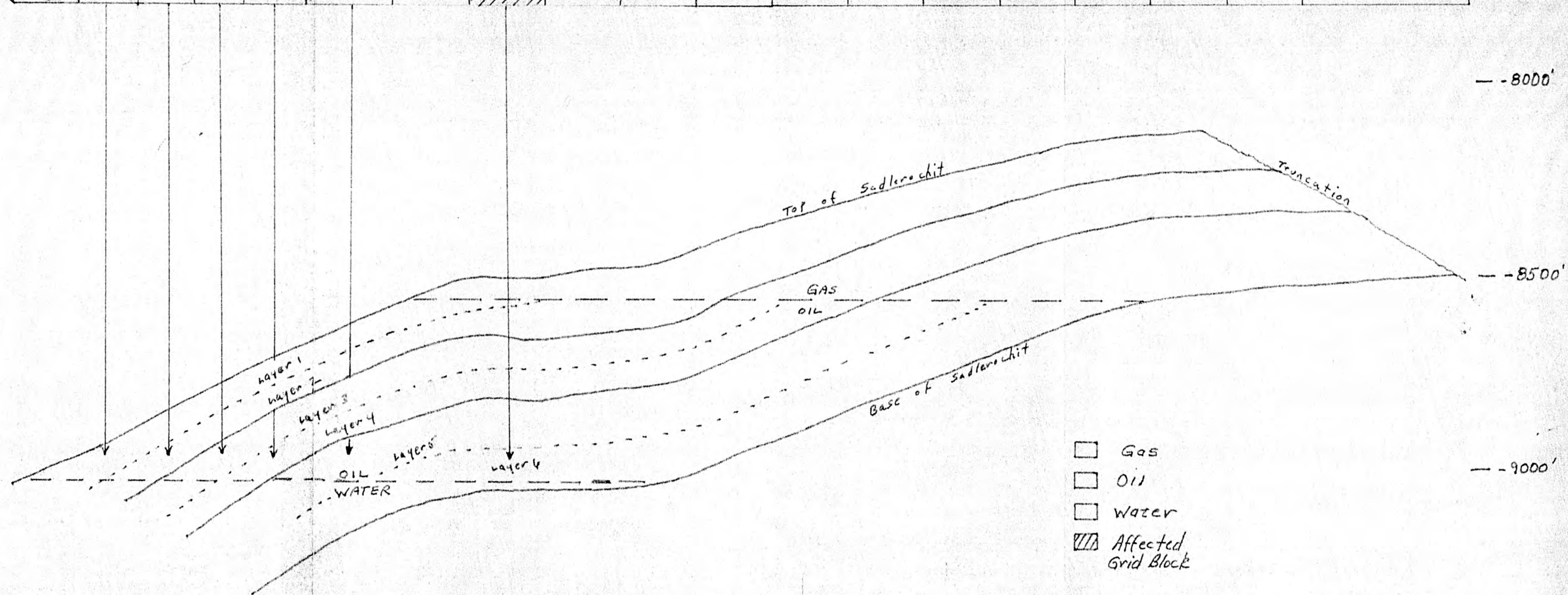
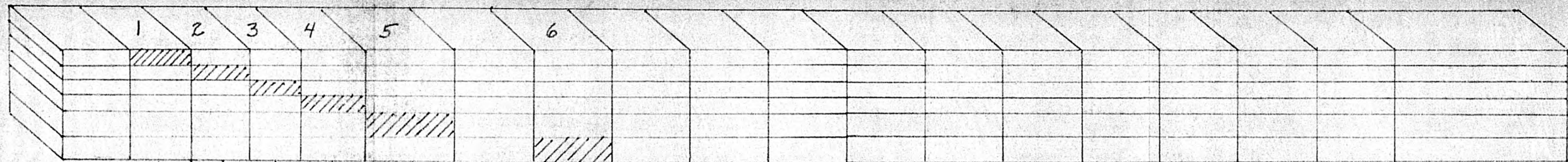
SCHEMATIC OF
CROSS SECTION

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SCHEMATIC OF
3-D MODEL

SCHEMATIC OF WATER INJECTION BY GRID BLOCK



- ☐ Gas
- ☐ Oil
- ☐ Water
- ☒ Affected Grid Block