STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO

14 June 1988

COMMISSION HEARING

VOLUME 2 OF 5 VOLUMES

IN THE MATTER OF;

A hearing in the matters involved in Cases Nos. 7980, 8946, 8950, 9111 and 9412.

CASES 7980, 8946, 8950, 9111, 9412.

BEFORE: William J. Lemay, Chairman
Erling Brostuen, Commissioner
William M. Humphries, Commissioner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

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I N D E X CONT'D

E X H I B I T S CONT'D

E X H I B I T S CONT'D

Thereafter at the hour of 8:30 o'clock a.m. on the 14th day of June 1988, the hearing was again called to order, at which time the following proceedings were had, to-wit:

MR. LEMAY: The meeting will come to order. Good morning, the second day of Gavilan and West Puerto Chiquito hearings, for those of you that might have drifted in and wondered where you were, and we are continuing today with our expert witness, Mr. Greg Hueni, and if you want to continue, Counsel, please begin.

MR. DOUGLASS: Thank you, Mr. Chairman.

GREGORY B. HUENI,

remaining under oath, resumed the witness chair, and the following proceedings were had, to-wit:

DIRECT EXAMINATION CONTINUED

BY MR. DOUGLASS:

Q We would like to identify for the record as Proponents Exhibit Twelve a graph of the daily gas rate, MCF per day versus top of the Niobrara A.

What have you shown here, Mr. Hueni?

A What we've shown here is a composite of three plots showing gas rate versus the top of the Niobrara A. This three plots we've reproduced individually in the individual notebooks, but we've put them for the sake of illustration on a single -- single graph and we've put color in the cots with red coloring so it's a little bit easier to see.

The three plots represent three different points in time. They represent normal rate test period, which this would be a month during that period, October of 1987; the lower -- the middle plot represents the month, December, 1987, when restricted rates had been re-introduced; and then finally we have March of 1988, once again a restricted rate producing month.

The -- the plot is -- the scale on the plot, the bottom axis is the top of the Niobrara A formation. It runs in all cases from the deepest point is 200 feet on the far lefthand side to, I think, 700 feet above sea level on the far righthand side.

So as you go from left to right you get structurally higher. The wells that are on the right side of the graph are the structurally higher wells in the field.

Q For instance, if you just turn these

graphs taking the right side and putting it at the top, then you'd have an arrangement of the highest wells down to the lowest wells, is that correct?

A Yes, that's correct.

Q In other words on the -- on the chart it's from right to left you go from high to low.

A Yes, that's correct. The vertical scale, or the Y axis, in all cases is the actual gas producing rate, not the gas/oil ratio but the actual gas that's coming from each well.

We've used a logarithmic scale in order to get all the data on in a reasonable fashion. The bottom line on this I believe is 10 MCF a day. Then we have 10^2, which is 100 MCF a day; 10^3, which is 1000 MCF a day, or a million a day; and then 10^4, which is 10-million a day. Once again, each of these cycles on logarithmic paper represents a change in order of magnitude.

The -- there are two points we want to make from this graph.

First this graph shows that the absolute amount of gas that's being taken from these wells in the normal rate period is essentially the same amount we're -- as we're taking in the restricted rate period. In other words, these points all tend to fall along in a band in basically the same place on the graph. It means that when we've gone to restricted rates we haven't restricted gas production at all. All we're restricted is oil production. So we're getting the same amount of gas out of these wells, we just aren't getting the oil with it.

That -- that's one point that we wanted to make.

The second point we want to make from this plot of behavior is that wells that are especially the highest wells are not the wells that are producing the large amount of gas. Basically the amount of gas production is evenly distribvted for wells regardless of their structural position. We would expect if we had a reservoir where we were forming a secondary gas cap at the top of the reservoir, that those wells would be wells that would produce with large amounts of gas, but that's not the case. Wells that are deep down in the reservoir produce just as much gas as wells that are structurally high.

It indicates to us that restricted rates, at least to the degree they're restricted now, are not successful in -- in causing gas to migrate upward, and in fact I think we can show from the preceding plot that the rate restrictions we already have are so severe that about the only way that we could restrict the rate further would be by essentially terminating production from the wells. So --

Q Mr. Hueni, one of the things you said there I want to see if I understand, is that did you indicate that -- that the normal rate of production versus two months of restricted rate of production, that essentially the restricted rate has not restricted the amount of gas produced but only restricted the amount of oil?

A I think that's fairly obvious from this plot.

Q Do you find any correlation that you're able to see on these that you've got a situation where the lower structural wells are producing the less -- less gas?

A No, the lower structural wells make as much gas as the wells that are the structurally highest wells.

Q All right. Anything else you want to add with reference to Exhibit Twelve?

A No, sir.

MR. DOUGLASS: Offer Exhibit Twelve.

MR. LEMAY; Exhibit Twelve is entered into the record without objection.

Q We've marked for the record as Proponents Exhibit Thirteen a set of charts entitled Plots of Gas/Oil Ratio Versus Top of the Niobrara A Subsea, Niobrara A Subsea, which is shown on Exhibit Thirteen.

A Exhibit Thirteen is a combination of six plots. We've presented the individual plots in our book but for the sake of comparison purposes we've presented them in a composite form on this exhibit.

The plots are individually the top of the Niobrara A formation measured in feet above sea level similar to the last exhibit, where we had a range in all cases from 200 feet above sea level up to a maximum height of 700 feet above sea level.

Q I believe that's the same distance that you used before but since you've got two graphs -- six graphs instead of three, you've compressed the scale to fit on the exhibit, is that right?

A That's correct. Each graph is the same bottom axis scale as the preceding exhibit had.

The vertical axis is gas/oil ratio. The last exhibit we looked at was strictly gas production and we said the gas production wasn't being affected by the restricted rates. We were getting as much gas out of the restricted rates as we were under normal rates.

Now this -- these graphs are of gas/oil ratios and what we've done is we have presented on the lefthand side, the three graphs on the lefthand side reflect the total spread of gas/oil ratios that we see in the Gavilan Mancos Area.

On the other hand, in order to present a little bit more exaggerated or detailed picture of the lower gas/oil ratio ranges, what we've done is we've expanded those wells that fall in the range of zero to 10,000 standard cubic feet per stock tank barrel GOR, and that's what we show on the righthand side. That's why we have the red lines that indicate that expansion of that (unclear) graph.

Q Let's get the gas/oil ratio scale that you have on the -- on the Y axis on the graphs on the left here.

A Okay. On the Y axis, or vertical axis, all of those gas/oil ratios are plotted on a linear scale. They run from -- the bottom of the axis is zero; the top part of the graph on the lefthand side is 150,000 standard cubic feet per stock tank barrel.

Q What's the heavy black line across the graph on the left?

A That is a gas/oil ratio of 10,000-to-1.

Q That's 10,000. And I notice on the graphs on the left you have some wells colored in red and some wells colored in yellow.

A The wells that are colored in red are those wells that have gas/oil ratios less than 10,000. The wells that are colored in yellow are wells that have gas/oil ratios greater than 10,000.

Q When you go to the more detailed graphs on the right, then the wells above 10,000-to-1 are not shown on the graph because there's not sufficient room.

A That's correct.

Q Let me ask you one other thing with reference to these. Are you covering the same three months that you did on Exhibit Twelve; that is, normal rate production in October of '87; restricted rate production in December of '87; and restricted rate production in March of 1988?

Yes, that's correct. Those are the three months that we cover. We have one normal rate test month and then we have two restricted rate months.

The -- the data on the lefthand side, the three panels on the lefthand side, show first, that the gas/oil ratios during the period of normal rate production are lower than they are during the periods of restricted rates.

Well, we know that makes sense because we saw basically the gas production staying the same but the oil production diminishing during the restricted rate period. So by necessity, gas/oil ratios had to increase during those periods.

We would note when we get down to the

March, 1988, situation, that it is so severe now, the restrictions in oil, while we're still producing the gas, that we term several of the wells -- several of the wells on the very bottom graph here, had gas/oil ratios greater than the statutory gas -- proration for a gas well of 100,000, so we've turned several of these wells into essentially gas wells by the rate restrictions.

Q If I -- if I add the numbers correctly, I see twelve wells that are yellow or above 10,000-to-1, at the normal rate production, and I see down here in March there are 1, 2, 3, 4, 5, 6, 7, -- approximately 36 wells now are above 10,000-to-1 in the March, the restricted rate month of March, 1988.

A Yes, that's correct. We've had a severe shift of wells from -- in their gas/oil ratios between the normal rate test period and March of 1988.

So the first point we would make from this, is the same point we made from the last one, is that restricted rates have not reduced gas production; they have simply reduced oil production, and they simply cause the gas/oil ratios to increase in the field and that increase ultimately means that we have to be less efficient in our producing mechanism and, therefore, we're causing waste.

On the righthand side we've expanded the scale to show the gas/oil ratios less than 10,000,and we have done this simply to illustrate that gas/oil ratio is not dependent on structural position. Once again, if you form a secondary gas cap, you would expect that the gas/oil ratio would -- would increase in the structurally highest wells and go -- and be very low in the structurally lowest wells, if you had gas segregation across the field to form a secondary gas cap, and that is not occurring.

So our restricted rates aren't really forming any kind of secondary gas cap in this particular field. They're simply restricting oil production and resulting in inefficient use of the gas energy of the reservoir.

Q Anything else you want to add on Exhibit Thirteen?

A No, sir.

Q Let's have identified for the record as Proponents Exhibit Fourteen a bar graph entitled Calculated Allowable Production Rates. What have you shown here?

A The graph that we show here is an updated version of a graph that was presented in the March, 1988, hearing. It was presented, I believe, there as Mallon Exhibit Fourteen, also.

What we've shown here is calculated allowable production rates based on what we see as the gas-oil ratio in March of 1988 based on the restricted Gavilan allowable.

Now, we have two cases presented here. The first case is all wells as they exist currently with the current Gavilan allowable set-up, restricted rate allowable set-up.

The second case is what the gas injection credit in the pressure expansion area would do to the relative producing rates of the pressure -- proposed expansion area of the Canada Ojitos Unit compared to the western two tiers, or the eastern two tiers of sections in the Gavilan Mancos Pool, so --

Q The expansion area.

A Yes, I'm -- I meant the proposed expansion area.

The data for the Gavilan, the eastern two tiers of sections in the Gavilan, as shown in the cross hatched symbol, in it a consistent 23 wells have been drilled.

By comparison, the data for the Canada Ojitos Unit is shown in the dark -- in the solid color, which is represented by 9 wells.

Q Let me get that. 9 wells, and what was it in the Gavilan?

A 23 wells.

Q Is that correct?
A That's correct.
Q The same, the same over here in the --
A Yes, that's correct.
Q Same number of wells.
A The -- the average gas/oil ratio for the 23 wells is, under the restricted allowables, and this once again reflects the -- the detriment of the restricted allowables increasing GOR's -- in the Gavilan Area the restricted allowables have increased the gas/oil ratio to a level of over 13,000. I believe it's actually 13,500-to-1 in March of 1988.
Q Is that the explanation as I remember, Exhibit Fourteen in the March '88 hearing, I believe that bar was -- was it 499 or 485? 499, I believe, or something in that range, is that correct?
A That's correct.
Q And it's now been reduced to 285?
A That's right, the --
Q Because of the gas/oil ratio restriction that's still caused the oil allowable to go down further.
A Yes, that's correct.
Q All right, sir.
A The 9 wells in the Canada Ojitos pressure maintenance area have a gas/oil ratio, reported

gas/oil ratio of 1274 standard cubic feet per stock tank barrel in March. The -- the net result is that the Gavilan wells, 23 wells in Gavilan, are reduced -- are restricted to a rate, 285 barrels a day, an average of about 10 barrels a day a well. Okay, it's about 12 barrels a day.

By comparison, the 9 wells in the Canada Ojitos Unit are producing an average of 190 barrels per day per well, a little bit -- little bit under 190, I guess. Well, I think it is 190.

Q I think you're right.

A Now, we would note that that 285-barrel a day rate that was being allowed out of the 23 wells in Gavilan includes the production out of the Howard 1-8, which we showed on our daily production plot in yesterday's exhibit had a capability under normal rates of producing 300 barrels a day. That well is restricted to 20 barrels a day. It includes the Ribeyowids, which had a capability of producing 90 barrels a day, which is restricted to 5 barrels a day.

The amount of production that's coming out of the wells in the Canada Ojitos proposed expansion area represents over 54 percent of the total production from the Gavilan Mancos area in March of 1988.

Q All right, sir.

A The -- the righthand side indicates what would occur were the proposed expansion area given credit for gas injection while rates remain restricted in the Gavilan Mancos area.

The rate, based on March of 1988, the Gavilan rate would be unaffected. It would still produce 285 barrels a day.

The 9 wells in the proposed expansion area would produce, and I will say this is a minimum value, would produce a minimum value of 2478 barrels of oil per day.

Q How much is that per well?

A Well, that's a -- that's about 275 barrels per day per well average.

The proposed expansion area, the proposed expansion area, the percentage of production coming from the proposed expansion area, the total Gavilan Mancos area production, would increase from 54 percent up to 63 percent of the total production, were the gas injection credit assigned to the proposed expansion area. In our opinion this is far in excess of either what would be suggested by correlative rights and second, it is far -- this kind of increase is far in excess of even what could be achieved through a secondary recovery project.

Q Let me ask this. What percentage did you say the current percentage is, the 1702, of the restricted rate production?

A 54 percent.

Q So the -- under the Gavilan restricted rate the wells in that two tier section we've been talking about, the producing wells in this two tier expansion area here, produced an amount greater than the entire rest of the Gavilan Mancos Pool, is that correct?

A That is correct. Those -- those are undoubtedly good wells. Even under normal rates of production they made about 49 percent of the pool production. They are -- there's no denying those are good wells but the restricted rates disproportionately benefit that side of the Gavilan Mancos Area.

Q Anything else you want to add with reference to Exhibit Fourteen?

A No, sir.

MR. DOUGLASS: Offer Exhibit Fourteen; offer Thirteen, also.

MR. LEMAY: Yes, those exhibits are admitted into the record without objection.

MR. DOUGLASS: Some lawyers say may I have a standing offer to offer my exhibits.

Q Let's see. Identify for the record as Proponents Exhibit Fifteen the bar graph entitled Calculated Allowable Production Rates. What is shown on

Exhibit Fifteen?

A Exhibit Fifteen is similar to the exhibit that we reviewed previously which was for -- which was a comparison of the proposed expansion area, the two tiers of sections on the eastern side of Gavilan Mancos Pool. This now is a comparison of the same type of performance for two individual wells, those two individual wells being the Mallon Howard 1-8, located in Section 1 of 26 North, 2 West, as wells as the BMG Canada Ojitos Unit No. 29, which is referred to as the E-6 Well, located in Section 6 of Township 25 North, Range 1 West.

Q Essentially direct offset wells.

A Direct offset wells, essentially equidistantly spaced from the lease line boundary.

These wells are wells that are very similar. They were subject to a pressure interference test. Extremely good communication was found between those two wells. They are, to our mind, two of the most comparable wells in the field.

This graph shows, on the bottom axis we show actually distance from lease line and the two bars are essentially equally spaced from the lease line, indicating they're -- they're equidistant.

On the vertical axis of both graphs we have plotted the allowable production rate based on March's gas/oil ratio in barrels of oil per day ranging in a scale from zero to 200.

Under current allowable limits the Howard Federal 1-8, which produces with a 12,200 gas/oil ratio is allowed to produce 20 barrels a day.

The Canada Ojitos Unit 29 Well, which produces with a gas/oil ratio in excess of 5000, is allowed to produce 46 barrels a day.

Q You've shown the lease line that you mentioned here between the two, is that correct?

A Yes, that's correct. Now once again, the Howard 108 is one of the wells that we showed the individual daily production plot for and we showed that when you went to low rate, you went to higher gas/oil ratios, and when you went to higher rates, you went -- you decreased in gas/oil ratios, so the gas/oil ratio, 12,200 reflects to a large extent the effect of rate restrictions. It doesn't reflect that it's a poorer well; it just reflects the effect that rate restrictions have had on it -- this well.

On the righthand side the gas injection credit, proposed gas injection credit, would not affect the -- the Howard 1-8. On the other hand it would then allow the Canada Ojitos Unit well to increase in production from 46 barrels a day to 164 barrels a day.

Q It would be almost 300 percent increase in production rate, is that right?

A Yeah. That's correct.

Q In your opinion what will happen between those two wells -- first of all, what appears to be happening right now due to current restricted rates?

A Well, even under restricted rates we would say that there would have to be some drainage occurring based on the inequality of producing rates.

Q How about if injection credit is given?

A And that is then going to then be -- it's going to be affected by injection credit.

Q All right, sir, and what happens with reference to the relationship between those two wells then with 164 barrels versus 20 barrels as far as drainage is concerned?

A Well, it certainly aggravates the drainage situation.

Q Anything else you want to add on Exhibit Fifteen?

A No, sir.

MR. DOUGLASS: Offer Exhibit Fifteen.

MR. LEMAY: Be accepted.

Q Well, Mr. Hueni, is there an explanation for why we see in this particular reservoir that when you have increased rates of oil production versus decreased rates of oil production, that you have gas/oil ratios going down with the increased oil production and you have them going up with the decreased oil production?

Is there -- is there --

A Yes, there is.

Q All right, and you've shown for purposes of illustrating your next answer Exhibit Sixteen, which we'll identify for the record, which is Imbibition Results in High GOR's at Low Oil Rates and Low GOR's at High Oil Rates.

A Yes, sir.

Q And have that identified as Exhibit Sixteen.

Tell us what you've shown on Exhibit Sixteen.

A Well, all of our exhibits up to this point have demonstrated that there is a clear relationship between high producing rates and low gas/oil ratios, both for the field as a whole and for individual wells. We've looked at it on a monthly basis. We've looked at it on a daily basis, and we have shown the impact that that restricted rate has had in terms of increasing gas/oil ratios and diminishing oil production for many of the wells out there.

We -- the physical explanation for why this occurs is really fairly simple. It does have to do with the fact that we have a heterogeneous reservoir. We'll refer to it as a dual porosity system, the way that Mr. Weiss has referred to it, the way that we have referred to it in the past.

Q What do you mean by heterogeneous?

A We mean that it's not -- it's not uniform. It's got some portions of the rock that are, let's say, highly permeable and have some other portions that are fairly low permeability, tight. So you've got basically two -- you have two regimes. We can refer to it as dual porosity; that part of the -- the pore space of the reservoir consists of low permeability portions of the rock and that low permeability portion of the rock, we refer to it as matrix, but we mean very specifically lower capacity fractures, microfractures and some matrix porosity itself.

Mr. Greer has referred to it as tight fracture blocks. We don't even object to referring to it in that sense. It is basically a heterogeneous reservoir with some portions being more permeable and some portions being less permeable.

We've represented on this figure that type of rock system and you can see we've pictured a large fracture, which we call a major fracture and it's flow through that major fracture that brings fluids to the well primarily, and it's responsible for the high deliverability of individual wells in the Gavilan Mancos area.

Q Now when you're talking about a major fracture, you're talking about one about 1 or 2 or 3 feet wide?

A No, I'm not talking about it anywhere near that wide. It's just -- it's very small physically but compared to the (unclear) sides and the other dimensions of the flow channels, it's very large.

And that major fracture will be carrying gas and oil to the well, gas and oil that's produced, and we've pictured the oil in red and the gas -- I'm sorry, the oil in green and the gas in red.

And what we have is we have feed into that major fracture system from this more -- from this minor fracture, microfracture, matrix porosity system.

Q Although, on this particular example you don't show the minor microfracture actually encountering the major fracture, this is just a one dimensional picture here and you've got -- you've got three dimensions in the reservoir occurring, is that correct?

A Yes, that's correct.

We've noted on the top a distance of

approximately 1 inch. The reason we put that 1 inch on there is in prior testimony Mobil had some televiewer logs and one of the things that they indicated off their televiewer logs was that major fracture spacing was very close in the Gavilan Mancos area; that they could see major fractures occurring a half inch to an inch apart. So these major fractures are very closely spaced and they link up all this minor fracturing and microfracturing and matrix porosity.

We testified previously that we think that most of the oil is contained in the matrix system itself, not in the major fracture system, and that is exactly what Mr. Weiss has testified to as well.

The -- now the situation that you have when you have flow from this low permeability rock into the major fracture system is that at the same time that you have flow into that, that fracture system, you also have something we refer to as imbibition, and imbibition is exactly what a sponge does. It's absorption. It's a sponge that's filled with air initially sucking up water and as long as we have some gas forming in this other than the major fracture system, if we have in forming in the lower permeability region, we slow down the rate on this -- of production on this well, basically that oil is going to be sucked into the lower permeability portions of the reservoir, gas is going to be expelled and basically the fracture is going to fill with gas. Now that's actually on the righthand side, Mr. Douglass, over there, is that the fracture fills with gas, the formation basically re-saturates itself with oil and so what we find, then, flowing to the well is primarily gas and we end up with a low gas/oil ratio, high gas/oil ratio, I'm sorry, I said that absolutely backwards.

Now that the second situation is what occurs when we have high producing rates. What we have is we still have some imbibition of oil from the major fracture back into the gas filled pore spaces so basically we have more pressure differential between the formation itself, between the low permeability area and the higher permeability area and that results in more flow from that lower permeability region into the -- into the fracture, and as a consequence, we make more oil.and we don't make as -- we don't make any more gas. The gas stays about the same but we make more oil and so the gas/oil ratio goes down, sort of like sponge; if you squeeze it hard, you squeeze the water out of it. If you don't hardly squeeze it all, the water stays in it. It's the exact -- exact same type of situation that we have.

So what happens if we are producing at very low rates and frequently shutting in wells, the oil is re-imbibing into the tighter portions of the reservoir, and what we're doing essentially is bleeding oil or bleeding gas out of that formation rock and so we're losing gas energy and it's not serving to expel the oil from the rock itself.

So what is resulting is that we are having physical waste resulting by bleeding off reservoir energy from the rock itself.

Q Has Mr. Weiss recognized this situation on page 9 of Exhibit Nineteen that has been submitted in this record?

A Yes, he has.

MR. DOUGLASS: We'd offer Exhibit Sixteen, if we might, Mr. Chairman.

MR. LEMAY: Sixteen is accepted without objection.

Q We'd like to have identified as Exhibit Seventeen -- it's not in your book because we didn't have this -- I'd like to have identified as Exhibit Seventeen page 9 out of Mr. Weiss' exhibit -- I believe it's Exhibit Nineteen, as I recall, in the record.

Tell us what you've shown here, what you've highlighted.

A What we've shown on Exhibit Seventeen is a quote from Mr. Weiss' report that reads, and it's highlighted in yellow, that "increasing the pressure difference between the fractures and the matrix was suggested by Elkins as a means of improving recovery efficiency in the Spraberry Trend. If this was applied in the field, the results were not well documented in the literature. The concept does have merit in the Mancos where the surface area available for flow from the very tight matrix is extensive due to the fracture system. Flow from the matrix could continue for a number of years following depletion of fracture storativity."

So basically Mr. Weiss has recognized the same type of phenomenon, that you have flow from the matrix into the fracture itself, and that is a result of the pressure differential that you create between the pressure and the fracture due to high drawdown compared to a higher pressure in the matrix rock itself. There are two different pressures in this system. There is a pressure characteristic of the fractures; there is a pressure characteristic of the matrix. And what you try and do is maximize that pressure difference to get the maximum flow rate of oil out of the lower permeability sections of the reservoir.

MR. DOUGLASS: Offer Exhibit Seventeen.

MR. LEMAY: Accepted.

Q I'd like to have identified for the record as Proponents Exhibit Eighteen an excerpt entitled The Role of Imbibition in Reservoir Performance is Well Documented in Petroleum Literature.

What have you shown in this exhibit?

A Well, this -- this exhibit is just another statement. We just quoted from Mr. Weiss' report regarding this -- this role of imbibition, or absorption, of the tight rock, of oil into the tight rock.

Well, this has been documented in previous engineering texts. One of them is the one that Mr. Douglass referred to previously, <u>Fundamentals of Fractured Reservoir Engineering</u> by a fellow named Van Got-Racht.

It is specifically of fractured reservoirs and one of the quotes in particular that we thought was particularly applicable to the Gavilan Area is that, "An oil re-imbibition process may take place when some of the oil produced through gas gravity drainage may re-imbibe into lower blocks which have been partially desaturated." That means that -- by desaturated it means it contains some gas in it. "In fact, during the descent of oil drops (displaced by gas) through fractures, the oil may enter into contact with the gassing zone blocks which are partially saturated with gas and oil. The re-imbibition of these blocks with oil is, in effect, a reduction of overall oil production in the reservoir."

Not a reduction in gas production; it's simply a reduction in oil production in the reservoir, and it results in physical waste.

Q Do you consider this a well recognized engineering principle for reservoir engineering?

A Yes, I do, and it's one of the reasons that secondary recovery by gas injection is not going to work in a dual porosity or dual permeability system, is because there is no tendency for the gas to spontaneously be absorbed in the tighter sections of the rock, basically the same way that a sponge works. The only thing that's going to absorbed into the rock is going to be -- is going to be oil. It's going be liquid. So you inject gas into this double porosity system, the gas is going to move right down the major fracture network and it's not going to contact any of the lower permeability sections of the reservoir.

And that's why secondary recovery in this kind of project just doesn't -- doesn't work.

Q The -- do you have any other evidence that imbibition is taking place as far as the physical condition of the wellbores?

A Well, it's been noted in the field that on many of these pressure tests following the low rate, low rate of production, that in measuring pressures, taking bottom hole samples, they're finding the wellbores totally filled with gas and no oil, and I think that's once again evidence that that oil is disappearing before it ever has a chance to get to the wellbore. It's basically being imbibed or re-imbibed into the lower permeability sections of the reservoir.

MR. DOUGLASS: Offer Exhibit Eighteen.

MR. LEMAY; Exhibit Eighteen accepted.

MR. KELLAHIN: Mr. Chairman, may we see the source document from which this is extracted?

MR. LEMAY: Yes, Mr. Kellahin.

MR. DOUGLASS: I confess, I had the source document here yesterday. I left it back in the room. I'll be happy to send somebody to pick it up. I'm sorry.

MR. KELLAHIN: May we withhold admission of that at the moment until we can look at the text later?

MR. DOUGLASS: Fine, don't have any --

MR. LEMAY: It will be held i in limbo until the original source document is presented.

MR. DOUGLASS: Let me send someone to dispel limbo here, if I can.

Q Mr. Chairman, let me identify two exhibits, if I might, at this time for the record. Exhibit -- I'm not sure what order that you have them in your boot -- there's a one page exhibit and then a report -- one page is on top. I would like to identify that as Exhibit Nineteen A, and the report is Nineteen B, and I've placed on the board Nineteen A, which is a page out of the report.

Would you tell us what you've shown in Exhibit Nineteen A and Nineteen B, Mr. Hueni?

A Yes. Exhibits Nineteen A and Nineteen B are quantifications, the amount of oil that's been wasted or lost as a result of restricted rates both in the past as well as what would be expected in the future as a result of continuation of restricted rates.

Exhibit Nineteen A is basically a summary of what's contained in Nineteen B. It reviews first the amount of physical waste which we estimated has been lost due to restricted rates in the period September, 1986, through March, 1988, excluding the normal rate test period.

We've -- we've made this calculation two ways and the two different ways that we have calculated it has given us a range of lost reserves between about 370,000 stock tank barrels up to about 441,000 stock tank barrels for that period of September '86 through March of '88.

Q Now you're not talking about lost allowable.

A I'm not talking about lost allowable. I'm talking about lost oil that will not be recovered.

Q Waste.

A Waste.

There the future loss of oil, additional waste which will occur in the future, in the event we continue on with restricted rates, that amount of oil we estimate between 606,000 stock tank barrels and 720,000 stock tank barrels.

So in summary, we see the potential waste associated with restriction of rates, and basically the restriction of rates means bleeding off of the gas from the formation without taking oil with it, that's -- that's really what the implication is, and we see the total physical waste as potentially amounting to between 976.000 barrels and 1,161,000 barrels.

Q In your opinion can the 600,000 to 720,000 amount of lost oil, can that be prevented if the production rates are restored to permit maximum recovery of oil with the gas in the Gavilan Mancos Area?

A Yes, that can -- that -- that recovery does not have to be lost but it will be lost if we continue to bleed gas off the formation without getting any oil with it.

Q Anything else you want to add with reference to Exhibit Nineteen A and Nineteen B? Nineteen B shows the mechanics of how you -- formulas that you used and the information therein, is that correct?

A Nineteen B does show that. I would like to make a point with respect to Nineteen B.

Q All right.

A That we -- there are two evidence as far as we're concerned, that the -- that the field as a whole operates more efficiently at normal rates than it does at low rates. One of those pieces of evidence we see is that for the field as a whole the pressure trend, the change in cumulative production per psi pressure drop, the field as a whole, that -- that trend indicates that you do not necessarily -- well, that we do not have any kind of -- of more efficient mechanism for the field as a whole in terms of cumulative production change per psi pressure change under restricted rates.

Now, Mr. Weiss has testified that when he looks at it on individual wells that he sees a change in cumulative production per psi pressure differential, but that is more a reflection of looking at pressures at the end of 72 hours than it is of looking at fully built-up pressures, because a fully build-up pressure is really going to reflect the pressure of the total volume of oil in the system, whereas the kinds of pressures he's looking at at the end of his 72-hour build-ups right following his -- his high rate test, he's looking at the pressure in the fracture system primarily. He hasn't really seen the full pressure response from the matrix yet.

So he -- he come up with a value of change in cumulative production per psi pressure differential which makes it look -- makes restricted rates look more favorable than normal rates, where the opposite is actually the case.

So we've used -- we've used the trend in field average pressures as opposed to any individual single well.

And the second thing that we have done is we have quantified through formulas that relate recovery efficiency to the amount of gas that you take out of a reservoir. We have also quantified the loss that way. Now, I think it's indisputable that we have seen less -- lower GOR's with higher rates. I think that evidence is totally indisputable. We certainly have many arguments with how you use pressures in this delta oil production curve delta pressure change, but we have quantified this two different ways and we have come up with basically the same answr both ways, that the range of lost oil recoveries is in the range of 16 to 18 percent of the production if you go with restricted rates as opposed to going with higher rates.

Q Anything else you want to add on Exhibit Nineteen A? Nineteen A or B?

A No, sir.

MR. DOUGLASS: Offer Exhibit Nineteen A and B.

MR. LEMAY: Accepted if there are no objections.

Q All right, up to this point in your testimony, generally we've covered the rate sensitivity or the rate insensitivity or reverse rate sensitivity that exists in the Gavilan Mancos Pool Area?

A Yes, that's reverse rate sensitivity.

Q Right, and now we're going to enter the area with reference to whether there is a barrier between the injection -- what we call the injection area and the expansion area and the Gavilan Mancos Pool as designated by the Commission.

A That's correct.

Q I'd identify now for the record Proponents Exhibit Number Twenty, a three graph exhibit entitled Comparison of COU Pressure Maintenance Area Field Pressure and Gavilan Field Pressure Data added through March, 1988.

What have you shown on this exhibit and is this a similar updated exhibit from the March, 1988, hearing?

A Yes, sir, this is an updated exhibit fro the March, 1988, hearing, and I that time I believe it was presented as Mallon Exhibit -- Mallon, et al, Exhibit Number Nine.

What this exhibit is, it's a three-paneled exhibit.

The upper lefthand panel applies to the Canada Ojitos Unit pressure maintenance project.

The lower -- the upper righthand panel applies to the Gavilan Mancos Area, which includes both the Gavilan Mancos Pool as well as the Canada Ojitos Unit proposed expansion area.

And then the bottom graph is a combination of the information presented on the upper two panels.

The upper panel on the left is a plot of cumulative production in thousands of barrels ranging from zero out to, I believe, about 7.8-million barrels. This is for oil production from the pressure maintenance area. The vertical axis is measured pressure. It is measured and corrected to a datum of +370 feet subsea.

The portion of the upper left panel that looks like a reprint is taken from Mr. Greer's exhibit, one of Mr. Greer's exhibits, in a prior hearing and it shows pressure decline that occurred initially in the pressure maintenance area. Injection was begun and then the decline became somewhat alleviated.

Mr. Greer has testified previously that he believes this decline in pressure continued even though he was injecting, that he had a decline in pressure in his pressure maintenance area.

We do have measured pressures. There were no measured pressures taken in the oil column between 1971 and 1988, but we do have pressures in the oil column in 1988 in several wells and those wells all are shown on the far righthand side of that -- that graph.

In 1982 the Gavilan Mancos Pool was discovered. The initial pressure there was actually at -- I think our tape slipped a little bit in making the exhibit -- was about 1800 psi, and we had several pressures. We plotted up all those pressures and there was a trend in pressure for that pool as a whole and that trend in pressure is shown by the heavy black line.

And the pressures that were taken in February of 1988, some pressures are above the black line and some pressures are below the black line, but that is still once again a field average trend in the reservoir pressure and that's what we're talking about, using the average trend.

Q Do you know about what that value is?

A That's a value of about, I think, 825 psi, somewhere in that neighborhood.

Q It's below the graph that you have on the previous exhibit, just extended it on down, is that correct?

A That is correct. Now, you know, I think it's important to recognize that several of the wells that are plotted on the upper righthand side are wells in the proposed expansion area. They are Canada Ojitos Unit wells in the proposed expansion area.

The wells -- the pressures that are shown on the upper lefthand graph on the other hand, in February of 19 -- or in February of 1988, are pressure maintenance area wells, Canada Ojitos Unit pressure maintenance area wells.

Now what we've done is we have converted both of these graphs from the scale of pressures compared to cumulative production. We've put them on a time basis and that's what we do on the lower graph. And what we see for the Canada Ojitos Unit pressure maintenance area is a decline in pressure observation 71. Then based on the information we had available to us through Mr. Greer's testimony and through -- through various model studies that have been done on this area, we show a projection in reduced reservoir pressure down to a level of about 1400 psi in February of 1988.

On the other hand, we have for the Gavilan Mancos Pool a pressure that was essentially an original pressure at the time it was discovered in 1982, representing a pressure differential of at least 30 -- or 350 pounds above what we believe the Canada Ojitos Unit pressure maintenance area pressure was, and then that pressure -- that pressure in the Gavilan Mancos Pool initially was above, but then by about mid-19 -- it looks like late 1986, the pressure actually was the same, and started to fall below the pressure maintenance area, and 19 -- March of 1988 the pressure was down around 825 psi.

Now, the point that we make from this is very simply that this is about as good an evidence of lack of interference as you could possibly have on a field. You have seen basically a field that's been on production for 20-some years not affecting the initial pressure in the -- in the Gavilan Mancos Area, and then you see a depletion of the Gavilan Mancos Area pressure without affecting the Canada Ojitos Unit pressure.

If you want to talk about interference tests, this is our mind the very best type of interference test that you could -- could rely on.

Q Approximately how long a period of time do you have an interference test until Gavilan pressures are determined?

A Well, we have 20 years of interference tests prior to the discovery of Gavilan, and then we have 25 years total on this interference test.

Q And you've shown here essentially the 25-year interference test?

A Yes, that's correct.

Q Now, as I understood Mr. Weiss on cross examination by Mr. Kellahin, he said that you would need 10 times that, as I recall, and I recall, and I'm not sure whether he was talking about the 100 pound differential or the 200 pound differential, but if it was 100 pounds, that would 1000 pounds, 10 times 100 is 1000, is that right?

A Yes, that's correct.

Q All right, and you have a 350 pound difference from Gavilan to the injection project at the time that Gavilan was discovered, is that correct?

A Yes, that's correct.

Q And you now have an 825 -- excuse me, a 625-- approximately 600 pound difference in 1988, is that correct?
A Yes, that's correct.
Q In other words, now Gavilan is 6 -- is 575 pounds, or approximately 600 pounds below the injection project, is that correct?
A Yes, that's correct.
Q If 1000 pounds is a standard, you've got 1000 pounds difference in the pressures that you've measured in these -- between these two fields in a period of approximately five years, is that correct, six years?
A Yes, that's correct. Yes, that's -- that's correct but I think the really important thing is -- is not the 1000 pounds as much as it is the fact that at one point in time the pressure is above and at a later point in time is below.
Q Do you -- first of all, let me ask, do you subscribe to the fact that you need 1000 pound pressure difference to show separate reservoirs between these two areas in this field?
A No, sir.
Q And what you're saying is that what you've really got here is pressure above in the Gavilan and it's now gone below and it hasn't affected the West Puerto

Chiquito Injection Project, is that right?

A Yes, sir, and, you know, I would point out that there are several other evidences we have of lack of communication.

We have very poor wells in the area between West Puerto Chiquito and Gavilan in many -- many cases. We've seen Gavilan come on production and go up to rates as high as 8000 barrels a day, and we've seen no change in the production profile in West Puerto Chiquito Pressure Maintenance Area.

I mean we have several pieces of evidence. This is just one piece of evidence. We have several what have been reported to be fracture interference tests previously, that show really no evidence of interference whatsoever.

So basically, there is no data to support any kind of communication. All the data supports just the opposite, that there is lack of communication.

Q Well, one of the exhibits you put in in the last hearing, Exhibit Five, was the map where you showed a number of shut-in wells and a number of which were in the immediate vicinity of where you had located the barrier, is that correct?

A Yes, that's correct.

Q Are you aware of any change in status

with reference to that area as far as this hearing is concerned?

A The data we had through March of 1988 indicated no change in status.

Q Anything else that you want to add with reference to Exhibit Twenty?

A Simply that the Gavilan Field, Gavilan Area, despite being down at 825 psi, has a capability to produce 6000 barrels day.

The --

Q Let me see if I understand that. The field you've got here that's got 825 pounds bottom hole pressure can produce 6000 barrels of oil per day?

A That's what it -- that's what it would appear, that it's -- of course it's on a restricted rate at this point in time, so we don't know for sure what its absolute capability is, but that's our estimate, that it's probably on the order of 6000.

Q Producing in the range of approximately 3000 barrels a day now?

A That's correct.

Q And what is the March production for the injection project area?

A The injection project area is producing 240 barrels a day.

So in and of itself pressure mainten- ance is not -- is -- just because you have high pressure i a reservoir doesn't mean that you necessarily have a high producing rate in that reservoir.

Q Anything else you want to add on Exhibit Twenty?

A No, sir.

MR. DOUGLASS: Offer Exhibit Twenty.

MR. LEMAY: Without objection Exhibit Twenty will be admitted.

Q Now, Mr. Weiss, I believe, was asked yesterday to look at the -- Mr. Greer's rainbow map and that was entered in the March, 1988, hearing.

Have you also looked at Mr. Greer's rainbow pressure map?

A Yes, sir, I have.

Q And have -- have you prepared what we will identify for this record as Exhibit Twenty-one, an analysis of that rainbow pressure map?

A Yes, sir.

Q What have you shown on this exhibit?

A What we have done is we've taken this rainbow pressure map which had been presented in the March, 1988, hearing, which was colored in multiple colors, that particular exhibit in our estimation gave the impression there there was a smooth pressure gradient between these areas of the Gavilan Field and the up-dip area of the Canada Ojitos Unit Area, and so what we have done is we've simply taken the pressures that were reported by BMG, which are surface corrected pressures which in part we don't totally agree with that, but at any rate, we have taken those pressures and we've plotted them across the field, measuring distance from the common boundary of the Gavilan Mancos Pool and the Canada Ojitos Unit.

Q In other words, the scale at the bottom of this graph is the distance from the current designated boundary between Gavilan and West Puerto Chiquito.

A That's correct.

Q All right, sir. And, of course, the BMG wells start at that point as far as going from that boundary to the east, is that correct?

A Yes. that's correct.

Q All right, sir, and you've taken the pressures that have been shown by Mr. Greer on his rainbow pressure map and plotted them in what manner as far as pressure locations on the surface?

A Yes. We've shown the pressures that were reported and that's what's shown on the vertical axis, ranging from the bottom of the axis is 700 psi going up to as high as 2000 psi.

Q All right. Show us how you plotted the pressures across that line.

A Okay. Well, we simply measured the distance of each of the individual wells going directly east from the boundary line of the Gavilan Mancos Pool.

And we take, we measure that distance in feet and we plot that versus the pressure that's shown on the rainbow map.

Q And what are the four yellow, excuse me, five yellow hexagons that you -- or octagons that you have put there?

A I think they're hexagons.

Q I think they're octagons.

A Okay, they're octagons; also look like circles.

The five yellow octagons are the pressure points that are shown in the yellow portion of Mr. Greer's map.

Q There's five pressures shown on the rainbow map and you've shown those five pressures with relation to how much pressure it was and the distance from the current boundary.

A Yes, that's correct.

Q Do you see any essential change in

pressure?

A Well, there are probably a few psi but I can't tell you off this map. I'd have to look at the values on them.

Q Well, I think it's -- why don't you look at them?

A Well, they range from 802 psi to 804 psi.

Q And what are the next -- the next area is a brown band on the rainbow map.

A Yes. The next area is a brown band on the rainbow map. That is the distance pressure profile for those four points. Two of the points almost overlay on each other and it's hard to differentiate.

Q There's two wells at approximately 8000 feet from the boundary?

A Yes, that's correct.

Q Current boundary of the pools and you've shown both of those.

A Yes.

Q All right, sir, and there -- now there's one pressure in the red boundary, 860. Where is it shown on your graph?

A Well, it's shown by the red -- red pressure point.

Q And it's closer to the boundary than one of the browns, is that correct?
A Yes, it is. It's further to the south, though, I believe, than the others.
Q Is the red one the highest pressure that you have west of the boundary that you've indicated here --
A Yes, sir.
Q -- barrier? All right, sir. What happens on the east side?
A The first -- well, the next, let's see, we have --
Q Green band?
A -- a green band.
Q 1, 2, 3, 4, 5 wells, 5 pressures in the green band, and you show 5 green dots.
A Yes, I show 5 green. Now one of those is shown as a triangle because one of those wells is actually an injection well. I don't know if it's active or it's very high volume. In fact, I'm sure it's not high volume but I'm not sure it's active or not.
But those 5 pressures basically fall -- they're 350 pounds higher than the -- than the preceding pressures that we've looked at and they are, once again, very uniform in their -- in their magnitude of pressures.
Q Well, even according to Mr. Greer's

rainbow map, at the barrier area there's about a 350 pound pressure difference, is that correct?

A Yes, that's correct. That's based on surface reported pressures.

On bottom hole fractured pressures as we see it, it's probably more like 450 pounds as of the date of these pressure measurements, which was November of 1987.

Q And I believe now you've indicated the pressure difference may be in the range of approximately 575 pounds.

A Yes, sir.

Q All right. I see the next band on his rainbow map is blue and he has two wells.

A Yes, sir, one of which is an injection well, the K-13 Well.

Q All right, sir. And the highest of those, that injection well pressure is 1292, and you're at about 1150, just immediately east of the barrier, is that correct?

A Yes, sir, that's correct.

Q All right, sir. Now, the next line -- the next color area is orange and he had two wells and you've shown those on here.

A Yes, sir.

Q And I see they're two triangles, is that correct?

Yes, sir, two triangles, it's two injection wells, the B-18 and then further to the east is the C-5 Well.

Q All right, sir. I see you've added some comments here, I believe, that were not on Mr. Greer's map, is that right?

A Yes, sir, we have added the comments at the B-18 Well. One of the things that concerned us very much when we saw this map is that the pressure measured in the B-18 Well was measured on November 19th.

The pressures for all the other wells that are shown, at least to the best of our knowledge, were measured on November 28th, nine days difference.

Well, the November 19th date happens to be the same date that injection was shut-in on the B-18 Well, so that well was injecting up to the day that it was -- pressure was taken on that. And we've seen pressure -- we've seen pressure fall-offs on several of Mr. Greer's injection wells and I think you'll note, if you see any of these, you'll note that between the time a well is -- a gas injection well is shut-in until it goes down to reservoir pressure, it takes it normally four to -- at least four days to go down to something that reflects reservoir pressure. Prior to that time you're simply reflecting what injection pressure -- what the localized pressure is right in the vicinity of the wellbore, because you haven't had the pressure distributed through the reservoir yet.

So this pressure gradient that is indicated by the B-18, we think is -- is probably not (unclear).

Q All right, sir. What have you shown in addition to that comment with reference to the B-18 Well?

A We took a pressure that Mr. Greer reported in the March, 1987, hearing. It was a pressure from the B-18 that was referred to as a fall, 1986, pressure and we put that pressure on this particular (unclear) and we -- we just simply put that on to show what the pressure was back at that point in time based on the static pressure survey that was taken in this well.

This also happens to be a well, the B-18 and K-13 Wells were involved in an interference test Mr. Greer ran, and he showed communication within a matter of hours between those wells.

So there's obviously excellent communication between those wells and there's no reason to suspect that there is a 400 pound or whatever the pressure gradient is between the B-18 and that first blue triangle there; that just doesn't appear to be realistic.

Q All right, what about the second

injection well here, pressure (not clearly understood) than the B-18?

A Well, we don't know too much about the specifics of that particular well. We know it's an extremely low productivity well and its cumulative injection up to about 1987 was about 200-million cubic feet.

We also know that in 1987 or so that -- that this well was returned to injection and that -- and that additional gas was injected into it, but we don't know how much in advance of this pressure measurement it was actually injected into.

So we see every possibility that that particular well, which is obviously a very low productivity is simply pressured out as a result of the injection that occurred into that well in 1987.

Q Well, when you said injection had ceased in 1972, and then right above it you say pressure after injection of 50,000 MMCF of gas, that 50,000 MMCF of gas was done in 1987 --

A Well, I believe that's right, and it may not be precisely 50 -- it's 50-million cubic feet, and it may not be precisely 50-million cubic feet. It was not a large volume of injection but it was a large volume of injection relative to how much had been injected into that well up to 1972.

Q And the best information you have is somewhere in 1987.

A Yes, that's correct.

Q What is your conclusion from your analysis of the -- Greer's rainbow pressure map?

A Well, our analysis is that there is not by any means any kind of uniform pressure gradient through that area; that on the lefthand side of what we interpret to be a barrier there are very uniform and very consistent pressures.

On the righthand side of the barrier there are very uniform and very consistent pressures, and that there is obviously something that is a significant barrier to flow occurring between the righthand portion, which is the pressure maintenance area, and the lefthand portion, which is the proposed expansion area.

Q Is that analysis of that map being consistent with the data and information previously presented here in the March hearing, for instance, with reference to Exhibit Twenty that you just put on?

A Yes, sir, it's == it's totally consistent.

Q Anything else you want to add on Exhibit Twenty-one?

A No, sir.

MR. DOUGLASS: Offer Exhibit Twenty-one.

MR. LEMAY: Without objection Exhibit Twenty-one accepted into the record.

Q All right, Exhibit Twenty-two is a chart showing Voidage Comparison: Normal versus Restricted Rates.

What have you shown on this exhibit?

A What we've shown is a comparison of, let's say, three parameters relating to reservoir perform -- or two parameters relating to reservoir performance for a restricted rate period between February of '87 to June of '87; for a normal rate -- a normal rate test period of July '87 to October of '87; and then back to the restricted rates between November '87 and March of 1988.

What this shows is that we have a more efficient mechanism when we produce at -- at normal rates than producing at restricted rates.

Q And how do you tell that from this?

A Well, you have to look and see what the two parameters, sets of parameters, we have on here are.

First, we have a calculation of voidage and this means how much fluid do we have to take from the reservoir, how many barrels do we have to take out of the reservoir in order to get a barrel of oil at the surface.

That's one parameter. That's what we

refer to as voidage and it's measured in terms of reservoir barrels which we designate by RB on -- that first number is 8.35 reservoir barrels to get one stock tank barrel at the surface.

Q In other words you have to void 8.35 reservoir barrels to get a barrel of oil that you can measure in the surface in your stock tank.

A Yes, sir, that is -- that is correct. That is a calculation that's based on how much oil, gas and water, if any water is taken out, how much oil, gas and water is taken from the formation and then how much that represents in terms of reservoir volume, and you need to have -- you have to take the pressure and you have to take the fluid properties and you can make that calculation.

Q How does that -- how does that comparison -- just that comparison, voidage, compare with the normal rates and the restricted rates?

A Well, you normally -- you normally expect to see voidage increase as pressure declines in a field that is a primary production field. So what we expect to see then, is we expect to see the voidage going up. So it goes up between the restricted rate period, the first one, from 8.35 to 9.72. That's an increase of about 1.4 reservoir barrels per stock tank barrel.

When we go back to the restricted rates, not only do we have pressure continuing to decline, but our gas withdrawals relative to our oil withdrawals becoming more significant. So instead of increasing by simply that 1.4 that we saw as an increase for the previous period, we now go up by about, oh, it looks like about 3. -- 3.5 reservoir barrels per stock tank barrel.

So basically, as we go to -- back to the restricted rates, we see once again a jump in the rate of voidage out of the reservoir and that just means very simply that we are using our gas energy less efficiently as we stay at restricted rates.

Q What is the other parameters that you have on here for comparison?

A The second parameter is what we refer to as -- what we've shown as delta N_p divided by delta-p, and this is the amount of oil production that's achieved for a pressure drop in the formation. So it's -- we refer to it in terms of barrels per psi, and this is once again based on field average trends. It's not based on individual well trends and we said once again you can't use individual well trends, particularly if they're just 72-hour points, because you see at the end of a normal rate period that that pressure is still building up significantly at the end of that normal rate period. That was shown on Mallon Exhibit Three.

Q Let me ask you on this first restricted rate are up here, if you produced 3176 barrels per stock tank barrel per psi drop, then does that mean that you'd have to void approximately 25,000 barrels of reservoir -- have 25,000 reservoir barrels produced to get one psi drop?

A Well, yeah, that's what it means.

Okay. The next period of time, the normal rate period, we continued on the same pressure decline trend on the average for the field. We showed that on -- on one of the prior exhibits where we drew on the decline trend, the average field decline trend.

So we take the cumulative production divided by the pressure drop and we see then the amount of oil production per psi pressure drop that we get has increased to 3,662. That's an increase of about 15 to 16 percent.

And then our final one is the restricted rate period again where the pressure drop and the cumulative production in that period of time is 3,144 barrels psi.

So we've gone -- under restricted rates we see about the same kind of cumulative production per psi pressure drop, basically about 3150, and then in the normal rate period we see a more efficient mechanism of -- producing mechanism of 3660 barrels psi. This is the 16 percent increase in oil production that we use as one of our quantifiers of lost oil.

Q Do you think this is a more proper way to gauge or to compare production per psi than the one that has been used by Mr. Weiss as far as individual wells are concerned?

A Well, yes. I think it's -- it's totally consistent. I mean you can't take more gas out of a reservoir and have it be more efficient. I mean that just doesn't make sense, and this is directionally correct, at least.

Q Anything else you want to add on Exhibit Twenty-two?

A Only that this is the proper measure to compare depletion under a primary depletion scenario, so if you're -- if you're going to deplete a field, pressure deplete a field, then this is the proper method to use, is to look at the barrels of psi pressure drop, to use that as one of your indicators.

MR. DOUGLASS: Offer Exhibit Twenty-two.

MR. LEMAY: Accepted without objection.

Q I'd like to have identified as Exhibit Twenty-three a bar graph entitled Voidage Comparison: Normal versus Restricted Rates.

What have you shown on Exhibit Twenty-three?

Exhibit Number Twenty-three is the same information we presented on the prior exhibit except it's presented in bar graph form.

There are three sets of bar graphs, one reflecting the first restricted rate period, February '87 to June of '87; the second reflecting the period July '87 to October '87, which is a normal rate test period ordered by the Commission; and then the third period, the restricted rates that went back into effect in mid-November and are still in effect today.

The lefthand side of the chart, which is the blue color, is the measure of voidage that we talked about previously.

The green bars represent the measure of amount of production. amount produced per psi of pressure change.

Q This just shows the bar graph form of what's shown on Exhibit Twenty-two.

A Yes. If you connected the -- if you connected the -- if you connected, for example, the tops of the blue -- of the blue things, you would see a definite increase in voidage rate when you did that. You'd see that your voidage rate becomes deeper, shallower between restricted rate and the normal rate, but when you go back to normal rate back to restricted rate, it becomes steeper and implies that -- that the normal rate helped alleviate the rate of voidage of this reservoir by reducing the amount of gas withdrawals from the reservoir.

By the green bars I think you can see that the highest one is the center one, the normal -- normal rate. Once again it's consistent that you would expect the best, the most production out of this reservoir per psi pressure change where you take out the least amount of gas.

MR. DOUGLASS: Offer Exhibit Twenty-three.

MR. LEMAY: Exhibit Twenty-three accepted without objection.

MR. DOUGLASS: Maybe this might be a convenient time (not clearly understood.)

MR. LEMAY: Why don't we take about ten minute break and that will give us a chance to get a cup of coffee or whatever.

(Thereupon a recess was taken.)

MR. DOUGLASS: Mr. Kellahin has had an opportunity, I think, to look at the (unclear) with reference to Exhibit Eighteen and I would like to re-offer Exhibit Eighteen at this time.

MR. KELLAHIN: No objections.

MR. BROSTUEN: It will be accepted.

Q Exhibit Twenty-two, Mr. Hueni, we've identified as a 3-panel exhibit with reference to the Comparison of Actual Oil Rate and Predicted Oil Rate and two other pressures there, a gas oil ratio and pressure.

Excuse me, I misspoke. It should be Exhibit Twenty-four. I'm sorry, I don't know what -- I notice my mind does that sometimes nowadays.

Exhibit Twenty-four, would you tell us what's shown here, please?

A Exhibit Number Twenty-four is what we presented to you in three separate panels. We put those three panels together on this display that we put on the easel.

What this is in general is a plot of historical production of Gavilan Mancos Are in terms of oil production and gas/oil ratios and also pressure trends.

It -- we did a study back in -- for the March, 1987, hearing. That study was basically completed in about January of 1987, January and February of 1987.

We present this because we believe that

production performance since that point in time is consistent with the results of our study. In other words, we felt we had something that was a valid model of the field and which we could use to predict future performance in the field, so we have studies historical performance and then also what we predicted through our simulation model.

The top graph is oil production. Our oil production historical is shown on a time scale; it's shown on a semi-logarithmic scale, or a logarithmic scale, I'm sorry, in terms of barrels of oil per day.

In general the oil production is in excess of the 1000 a day -- well, 1000 a day horizontal line. It, in fact, gets up to as high as 6-7000 (unclear) -- yeah, right.

And then you can see -- basically the end of our simulation study was in early 1987 and of course, we weren't able to predict what -- what allowables would be, and that's basically a Commission's function, but we -- we've predicted -- we've made a prediction case, however, based on a capacity at that time of about 7200 barrels of oil per day, and then carrying that prediction out where we are now, our prediction indicates that if this field is returned to normal rate production, that basically the trend in the future production will be on the order of what we show by green -- green dots.

The next panel down is gas/oil ratio. Once again we matched history up through about 1987, end of 1986, in terms of the general shape of gas/oil ratio trend, and we predicted what we would expect gas/oil ratios to do subsequent to that time. And what we expected is that it would come up and it would more or less level off and maybe eventually even decline a little bit. But what's really happened, and I think this is perhaps noteworthy, is that those periods of time where we have had significant restrictions in producing rate, the gas/oil ratio has been much higher than what we would have predicted; however, when you go back to normal rates, the gas/oil ratio goes back down to (unclear) predict at. Then at the end, in November of 1987 we returned to basically restricted rates and once again the gas/oil ratio went up considerably above what the simulation study predicted value would be.

We've shown on the bottom graph pressures, the actual pressure trend, field average, as we've identified it, is the solid line.

Our -- our simulation model output is shown by the X's that are colored in blue on this -- on this exhibit.

What we show is that we match up in general with the field pressure decline trend that's been observed and that we expect the pressures to continue to decline off, and, of course, rate will decline off, too, and eventually that pressure decline will moderate a bit.

The pressures that we've reported here represent an average pressure. It's important to recognize that this thing we call reservoir pressure is some combination of pressure in the fracture system and pressure in the matrix; matrix contains the bulk of the oil. What we're showing here is the average pressure trend for the combination of matrix and fractures. What we may be measuring in the field, however, may be something in between that average trend. It may be a pressure more reflective of fracture pressure at any given time.

Q What conclusions do you draw from this exhibit?

A Well, what we -- we've drawn two conclusions. One, believe that our model is field accurate in portraying what future performance can be expected for the Gavilan Mancos Area; that we can expect an ultimate recovery from this area of about 9.39 million barrels. That includes also the oil -- that also includes recovery from the Canada Ojitos Unit pressure -- proposed expansion area.

It also indicates to us that high -- that restricted rates have resulted in that, normally high gas/oil ratios, whereas normal rates have resulted in something that would be more consistent with expected gas/oil ratio performance.

MR. DOUGLASS: Offer Exhibit Twenty-four.

MR. BROSTUEN: Without objection it will be accepted.

Q I'd like to have identified as Proponents Exhibit Twenty-five a comparison of oil recovery, Gavilan Mancos Are and Canada Ojitos Unit pressure maintenence area.

Would you discuss what's on this exhibit, please?

A Yes. This exhibit shows a comparison of the performance of the Gavilan Area, which once again includes the proposed expansion area of Canada Ojitos, and compares that to the pressure maintenance area in the Canada Ojitos area.

This graph is shown simply to illustrate the fact that the pressure maintenance area has not performed significantly better in terms of at least the indices that we have available to us than has the Gavilan Area, and in fact, the Gavilan Area has recovered the oil production that it has recovered in a much -- much shorter period of time.

What we show here is a comparison of the Gavilan Area. That consists of 47,200 acres. Now we, I think, have been fairly liberal in what we consider to be the Gavilan Area, because we've included from the base map everything that's colored in green, as well as everything that is colored in the green and white striping

On the other hand we've compared that to the Canada Ojitos Unit pressure maintenance area, which consists of a reported 50,000 acres. Actually, the area that's shown in brown there is somewhat in excess of 50,000.

Our first basis for comparison is what happens -- what's occurred in the first five years of full development. There's no magic about five years; it's just something that we felt would realistically portray how fast the fields have been brought on in a comparative sense.

In the Gavilan Area 3.7-million barrels have been produced in the first five years, representing 78 barrels per acre.

We compared that to the Canada Ojitos Unit pressure maintenance area, 1.11-million barrels have been produced, representing 22 barrels per acre.

Now looking at March, 1988, this represents six years of production from the Gavilan area, and 25 years production from the Canada Ojitos Unit Area.

The barrel recovery, 5.5-million barrels for the Gavilan Mancos Area, 7.9 for the Canada Ojitos Unit

Area.

On a per acre basis 117 barrels per acre compared to 159 barrels per acres recovered over 25 years.

Q Now, let me ask you, on a yearly basis how much has been the average production for the 6-year life of Gavilan Area?

A Gavilan has produced at an average rate of about 920,000 barrels per year, even with the restricted rates.

Q 920,000 barrels per year. And how much has the unit, injection -- pressure maintenance area produced per year?

A The pressure maintenance area has produced about 317,000 barrels per year.

Q All right, sir.

A Also with respect to March, 1988, you're dealing with the Gavilan Field which has a capability which has a capability of producing, we believe, as much as 6000 barrels of oil per day.

Q All right, sir, so the current ability is about 6000 barrels of oil per day.

A That's right, and of course it's restricted at about 3000 barrels per day, and we compare that to the Canada Ojitos pressure maintenance area, which in March produced 243 barrels a day.

We have estimated ultimate recovery for the Gavilan Area, which is both inclusive of the Gavilan Mancos Pool as well as the Canada Ojitos Unit proposed expansion area, of 9.39-million barrels. That's based on the work that we have done previously. The actual amount is 199 barrels per acre.

We have estimated ultimate recovery prior to blowdown for the Canada Ojitos Unit pressure maintenance area of 8,032,000. That's based on decline curve analysis indicating about 200 -- or about 104,000 barrels of oil remaining; dividing that by 50,000 acres indicates a recovery of 161 barrels per acre.

Q What's your conclusion, then, with reference to primary production from the Gavilan versus the injection area?

A Well, we certainly don't see anything to indicate that the Canada Ojitos Unit pressure maintenance is -- that the application of secondary recovery there will necessarily increase recovery over that that we could obtain through primary production at Gavilan.

Q Anything else you want to add on Exhibit Twenty-five?

A No, sir.

MR. DOUGLASS: Offer Exhibit Twenty-five.

MR. BROSTUEN: Accepted.

Q Identify for the record as Proponents Exhibit Twenty-six a tabulation entitled Fractured Mancos Fields. What have you shown here?

A We've shown several performance indicators for five -- six -- five fractured Mancos fields and in addition we've also shown the West Puerto Chiquito Pressure Maintenance Area for comparison purposes.

We've shown this for the Boulder Mancos, the La Plata Gallup, the Otero Gallup, the East Puerto Chiquito, the Verde Gallup, and then, of course, the West Puerto Chiquito Pressure Maintenance Area.

The information that we have shown on here has been taken from reports published by the Four Corners Geological Society, including the estimated productive acres as well as the number of wells.

They have also reported the production history on these fields and we have, where necessary, extrapolated that production history to come to an ultimate recovery.

Looking at the Boulder Mancos Field first, to pick what -- what information we have, we have first the recovery through December of '87 for the Boulder Mancos. It was 1.8-million barrels.

Q I believe that's the same figure that

Mr. Weiss used yesterday, approximately.

A Yes, that's correct. The estimated area for the field is 2000 acres.

Q And I believe he had 4000. Where did you get your 2000?

A Well, our 2000 comes from Four Corners Geological Society estimate of productive acreage.

The type of production was primary. There was no secondary recovery attempted in this field.

Dividing the recovery by the number of acres we arrived at current recovery of 905 barrels per acres, which required 12 years to produce.

We list the primary operator, Mobil. There were some other operators in the Boulder Mancos Field.

And then we list the estimated ultimate recovery in terms of barrels of per acre and since Boulder is pretty well depleted we have a value of 905 barrels per acre there.

We've also then shown the number of wells, 25 wells in the Boulder Mancos Pool, and that implies then the area per well, the density of drilling, is 80 acres.

Q I believe you just covered the number of wells, 25, that's 80 acres per well, is that correct?

A Yes, that's correct.

Q Let's see, first, let me ask you this. Have -- other than the West Puerto Chiquito, have any of the other fractured Mancos reservoirs had a pressure maintenance project or secondary recovery instituted?

A According to the reports that we reviewed from the geological society, a gas injection project was attempted in the La Plata Gallup Field, which experienced -- gas injection was ceased, at least temporarily due to a premature breakthrough of injected gas into producing oil wells.

Q You noted that as "secondary failed" on this exhibit?

A That's correct. We might note with respect to La Plata Gallup, also, it has a very steep dip. It has -- similar to the Boulder Mancos, which is about 2000 feet per mile, the La Plata Gallup has a dip of, I believe, also about 2000 feet per mile.

Q In recovery per acre of these fields, they range from a low in that La Plata of 230 versus a high of 905 in Boulder. Is that correct?

A Yes, that's correct.

Q How does the West Puerto Chiquito Pressure Maintenance Area fit into that comparison?

A Well, the West Puerto Chiquito Pressure

Maintenance Area is the lowest of the six fields that are shown on the graph. It has a recovery of 161 barrels per acre, requiring a year to produce 90 percent of that volume. It's 22 years so it's also one of the longest lived fields.

We show 11 wells in that field but I think in reality we know there are a few more wells than that because we've got them on our map. I think that 11 well number actually should be changed to 14 producing producers and 5 injectors.

Q That would be a total of how many?

A Well, then we could put in a total of 19 wells.

Q All right, but 14 of them have been producers and 5 injectors for a total of 19?

A Yes, that's correct.

Q All right, if you do that for the pressure maintenance area, what is the change for the acres per well?

A Well, it reduces the acres per well from 4045 per well down to 2631 acres per well.

Q Okay, 2631. All right. What conclusion, if any, do you draw from this exhibit with reference to the fractured Mancos Field?

A Well, it's difficult to see that the

West Puerto Chiquito Maintenance Area has significantly increased recovery to the -- effect, to the extent that it would be as good as any of the others that have produced under a primary drive mechanism.

We might also note, although it's not a perfect correlation, that the -- some of the fields that have experienced the highest recoveries also appear to have the greatest well density, but I don't know that that's necessarily a direct correlation.

Q It is an observation you can make from the exhibit.

A I think that's factually stated, that the best recovery is in the smallest per acre spacing, whereas, the poorest recovery is in the largest per acre spacing.

Q Do you recall me visiting with Mr. Weiss yesterday about his formula that used gravity as the angle of the -- of the -- or the size of angle of the reservoir, as I recall. Do you recall that exchange?

A Yes, I do.

Q Have you made any calculations to determine, for instance, what -- at a volume produced from Boulder Mancos, what, with its angle of dip, what volume could be produced from the West Puerto Chiquito from the West Puerto Chiquito Pressure Maintenance Area, and what volume could be produced from Gavilan, using that same formula?

A Yes, sir. That -- that formula relates to how fast you can produce a field and expect to have gravity drainage assist in the recovery mechanism, and I have made those calculations.

Q All right, sir, and what are -- for the Boulder Mancos what would it be?

A For the Boulder Mancos, which has a dip of about 20 degrees, if you use that as a standard and you said that you would allow a well to produce at 1000 barrels a day in that field --

Q All right, 1000 barrels a day, okay.

A And then you went over to West Puerto Chiquito and you considered the fact that West Puerto Chiquito may only have an angle of dip of maybe about 5 degrees, then you don't get as much gravity drainage benefit in West Puerto Chiquito, so you wouldn't be able to produce West Puerto Chiquito over about 225 barrels a day.

Once again, this is just a comparison. It's not absolute values. It's a comparison of how effective the angle of dip is in supporting gravity drainage in these fields.

Q As I recall in visiting with Mr. Weiss, he said that he thought that would be lots between the --

the difference between the 2000 feet per section and 450, or so, feet per section in the West Puerto Chiquito.

A It's a difference of -- by a factor of about 4 --

Q All right, sir.

A -- because of the difference in the angle of dip.

Q All right, now what about if I were to add over here Gavilan Area?

A Well, the Gavilan Area has, I think, a maximum angle of dip of about zero -- well, 0.5 degrees. You said West Puerto Chiquito had 5 degrees, Gavilan's down to 0.5 and, in fact, many portions of Gavilan is less than that 0.5 degrees. In fact, some of it's essentially flat.

So the maximum rate you would be able to produce out of Gavilan and still have gravity drainage, at least compared to these others, would be 22 barrels of oil per day.

Once again we're judging this all on 1000 barrel a day standard.

Q Then as far as gravity being a significant factor in the production from the Gavilan Area, according to Mr. Weiss' formula, what is your opinion?

A I -- well, Gavilan has probably only -- at most, a tenth of the gravity drainage potential that the

West Puerto Chiquito Field had, or 1/40th of the potential that the Boulder Mancos Field had.

Q Anything else you want to add with reference to Exhibit Twenty-six?

A No, sir.

MR. DOUGLASS: Offer Exhibit Twenty-six.

MR. BROSTUEN: Accepted.

Q Let's have identified for the record as Exhibit Twenty-seven a tabulation entitled Revenue Loss to the State of New Mexico. Would you tell us what is shown on this exhibit, please?

A Since the period of restricted production was begun, there has been a considerable amount of revenue loss, both to the State of New Mexico and to the operators and royalty interest owners in the Gavilan Mancos Area. This is Figure 20 -- or Exhibit Twenty-seven is a quantification of this revenue loss. Some of it is -- a portion of it is a temporary loss until rates are restored. Other portions of it are an absolute loss because we are not going to recover all the oil that we would have recovered that we would have recovered had we produced the field at capacity.

Q What have you determined to be the revenue loss to the State of New Mexico, total?

A Well, the total loss is $4.3-million and the three components of that are revenues of $1.9-million lost as a result of lost oil taxes; $850,000 lost as a result of lost gas taxes; and then the State's share of the Federal royalties of about $1.5-million; and finally, royalties on State lands of about $50,000.

Q How much of that do you estimate will be permanently lost?

A We would estimate of the -- of the $4.3-million, about $1.2-million has been permanently lost.

That correlates with the fact that we could have produced another 1.4-million barrels in this time frame between September of '86 through May of '88 and then it's -- then losing during that same period 400,000 barrels. So it represents about, oh, I guess about --

Q Exhibits Nineteen A and Nineteen B are the ones that showed that permanent loss, is that correct?

A Yes, that's correct.

Q All right, sir. Anything else you want to add with reference to Exhibit Twenty-seven?

A Very simply that if restricted rates are continued into the future, that in addition to the $1.2-million that's been permanently lost, an additional $2-million will be permanently lost, so restricted --

Q To the -- to the State of Texas -- State of New Mexico.

A To the State of New Mexico, so the total loss to the State of New Mexico would be $3.2-million. The remainder of the -- of the revenue is deferred.

MR. DOUGLASS: Offer Exhibit Twenty-seven.

MR. LEMAY: Accepted without objection.

Q We identify for the record as Proponents Exhibit Twenty-eight a tabulation entitled Revenue Loss to Working and Non-Federal Royalty Interest. What is shown on Exhibit Twenty-eight?

A This is a calculation for the revenues that would be lost for the working and non-Federal royalty interest, a similar calculation to what was done for the State.

What is shows is that the balance of the parties involved in the Gavilan Mancos Area will -- have had revenue loss in the amount of $28.5-million, and actually. I guess, from that we have to subtract off the amount that was accounted for as lost to the State taxes and royalty of $4.3 and also $1.5-million that the Federal government has lost.

So the loss to the operators and

non-federal royalties is in the amount of about $22.7-million.

Now a portion of this, once again, is an absolute loss and part of it is a deferred loss.

Of the $22.7-million, $6.35-million has been lost permanently. That should be a 35 instead of a 53.

Q Excuse me. Sometimes I have dyslexia of the ear.

A The --

Q That's a permanent loss.

A That's a permanent loss for past production. That's already what's been lost.

In addition to this, there is an additional loss in the future if restricted rates are to continue, in the amount of about $10.3-million, resulting in a total potential loss, physical loss, of $16.7-million.

And I might add, in my opinion, I think that's probably on the low side because if restricted rates continue, there are going to be many wells that are going to have to be prematurely abandoned because they're going to be uneconomic to produce and it's very likely that that loss could be more substantial.

Q All right. These last figures you gave me, 6.35 in the past, that is a permanent loss as a result of the waste that's occurred, is that correct?

A Yes, that's correct.

Q The $10.3-million in the future again is a permanent loss that is waste.

A That's correct.

Q It's not just a loss of income. The loss of income to date has been $22.6-million or $22.7-million, versus the $6.35-million permanent loss, is that correct?

A That's correct.

Q In other words, the operators and the non-Federal royalty owners would have an opportunity to recover the balance of the $6.35 from the $22, about $16-million in the future if the rates are restored.

A That's correct.

Q All right, sir. Anything else you want to add on Exhibit Twenty-eight?

A No, sir.

MR. DOUGLASS: Offer Exhibit Twenty-eight.

MR. LEMAY: Exhibit Twenty-eight accepted without objection.

Q As far as this witness is concerned, as Johnny Carson would say, this is the last exhibit, Twenty-nine, which is marked as a Summary of Prior Studies.

Would you tell us what you've shown on Proponents Exhibit Twenty-nine?

A Once again we -- we have been studying this in conjunction with several other companies since prior to the March, 1987, hearing. We arrived at a number of conclusions that we still hold. They have been the basis for our testimony in March of 1987 and March of 1988, and basically they are still -- still valid today as we see them.

Those conclusions include the fact that we believe that the Gavilan Mancos Pool produces from a dual porosity system, which consists of major fractures and matrix, which consists of secondary porosity -- I put down primary but it should be secondary porosity -- microfractures, and small -- small scale fracturing.

Q If you were a geologist you'd put "secondary" down instead of "primary"?

A That's right, I would have said it's secondary.

We also concluded, based on lab tests, two things, and this isn't worded very well, but it -- we based -- we concluded that we have a high degree of rock compressibility and we also concluded that we had flow into the matrix. During our lab test we injected fluid into the matrix, and we know that matrix will accept fluid, so there's no reason to suspect it won't produce fluid back.

We concluded that the oil in place value, based on material balance, is about 55,000,000 stock tank barrels for the combination of the Gavilan Mancos Pool, as well as the Canada Ojitos Unit proposed expansion area.

We felt that the in situ oil permeability thickness, basically the average for the drainage area of these various wells, was less than 1000 millidarcy feet. We based that on pressure build-up; we based it on well performance. We still believe that.

We believe that there is gravity segregation vertically in the fractures. In other words, we see gas at the top of the producing interval and oil at the bottom. We do not see gas moving across the field, however. We see gas only accumulating vertically in the reservoir at a given point. That's based on production logs and gas/oil ratio performance.

The next conclusion is one in which we dropped out a key well -- or key word. We say, "Gavilan produced from Niobrara A, B, but not C."

It should be, "Gavilan produces primarily from Niobrara A, B, but not C."

Q We'll add that in there.

A We have testified, and we agree with Mr.

Busch's conclusions that there is some C zone production in the Gavilan area. We have also stated, as Mr. Busch said, that that C zone production is relatively minor in comparison to what comes with the Niobrara A and B.

That -- that conclusion was supported by production tests, production logs, and televiewer logs, all of which were reviewed by Mr. Busch.

We said that Gavilan and Canada Ojito Unit, the proposed expansion area, were in excellent pressure communication. We have pressures showing very minimal gradients across the current boundary.

We also have interference tests between wells that -- in those two areas.

We said that Gavilan and the Canada Ojitos Unit pressure maintenance area is not in communication. We've presented a 25-year interference test and we also have available the Commission ordered pressure tests.

We also have the fact that no effect has been observed on the West Puerto Chiquito performance as a result of Gavilan.

We have simulated Gavilan historical performance and predicted future performance indicating an ultimate recovery of 9.4-million barrels. We still believe that is supported by the data but we believe it's supported only by the data provided that the restricted rates are lifted because otherwise the gas/oil ratios go considerable above what we predicted in our study.

We said at the time the Gavilan ultimate recovery was not reduced by increased rates. We base that on our -- our reservoir study and our reservoir model and we based it also on field performance.

That's still valid, but we're ready to change that, now. It's actually, it is not reduced, it's increased by increased rates.

Q So ultimate recovery is not reduced by increased rates but increased.

A And we now have available to us the results of the Commission ordered testing period that show that high oil production rates result in reduced gas/oil ratios and more efficient use of gas.

And, finally, we've concluded in the past and we still believe this to be the case, the gas injection in Gavilan will not improve but will hurt current operations. Gas injection, gas will not be imbibed into the lower permeability sections of this dual porosity system and therefore we will not get any oil out of that section of the reservoir.

The way to get oil of that portion of the reservoir is not to bleed the oil off slowly through reduced rates, but it is to produce the field at maximum capacity and try and create as large a pressure differential between the formation and a major fracture system and overcome these imbibition forces.

Q Anything else you want to add with reference to Exhibit Twenty-nine?

A No, sir.

MR. DOUGLASS: Offer Exhibit Twenty-nine.

MR. LEMAY: Twenty-nine accepted without objection.

Q Mr. Hueni as a result of your almost two years, and you have been studying this field for approximately two years, now, is that correct?

A That's correct.

Q And as a result of those studies, your view of your findings and the input from the various Gavilan Pool Proponents, and their engineers and geologists, do you have a recommendation to make from your standpoint as far as a reservoir engineer to this Commission with reference to the production procedures and field boundaries which should be instituted in the Gavilan Mancos pool area and the West Puerto Chiquito Mancos pool area?

A Yes.

Q And what are they?

A With respect to production procedures, we believe the wells should be produced at a capacity allowable; that through -- through producing at capacity allowable we'll maximize the recovery from the lower permeability sections of the reservoir.

Second, with respect to the boundary, (unclear) Gavilan Mancos Pool boundary, we believe it needs to be moved from what is considered -- from what I would consider to be an arbitrary township line to an actual physical boundary line which is two tiers of sections to -- to the east of its current position.

Q All right, on Exhibit Five in this proceeding have you placed a dotted line, a round dotted line, where that boundary would be under your recommendation to the Commission?

A Yes, sir.

Q All right. With reference to the use of injection credit from the brown area, from the injection are, with regard to the proposed expansion area, what is your recommendation with reference to that?

A I would recommend that no injection credit be given to the area that is in the proposed expansion area. It's not in pressure communication with -- with the pressure maintenance area, and it would aggravate an already serious drainage problem, increasing that portion of the field's ability to produce up to -- to as much as 63 percent of the total pool, Gavilan Pool, production.

Q Anything else you want to add with reference to your testimony, Mr. Hueni?

A No, sir.

MR. DOUGLASS: Pass the witness.

MR. LEMAY: Excuse me a minute. Let's go off the record a second, or we can stay on.

Do you plan to ask some questions of this witness, Perry, and -- okay.

MR. PEARCE: I have a few, Mr. Chairman.

MR. LEMAY: None, Mr. Lund?

Okay, well, we can start and continue at this point and then when the Proponents are through with with witness, then we might just take a break.

Fine, Mr. Pearce may continue.

MR. PEARCE: Thank you, Mr. Chairman.

FURTHER DIRECT EXAMINATION

BY MR. PEARCE:

Q Mr. Hueni, were you in the hearing yesterday when Mr. Weiss was testifying?

A Yes, sir, I was.

Q Do you have a copy of Mr. Weiss' exhibit with you?

A No, sir, I don't have that with me up here.

Q If I may, Mr. Hueni, let me hand you a copy of Mr. Weiss' exhibit and I'd ask you to turn to page 7 with me, please, a page that I asked Mr. Weiss some questions about.

Specifically my questions to Mr. Weiss dealt with the formula shown at the top of page 7. I want you to help me understand what that report says Mr. Weiss did.

As I understand it, Mr. Weiss did a calculation involving the B-32, B-29 and C-34 Wells.

A Yes, that's correct.

Q All right, and he assumed that all of the area which would be covered by a rectangle, including those three wells, was equal to the performance and all the well characteristics of the B-32 Well, is that correct?

A Yes, and I think it would be fair to say that Mr. Weiss assumed the uniformity across what we consider to be the barrier.

Q And the affect of that was that in his model, if I may use that word, is that there is no barrier.

A That would be how I would interpret it.

Q And were you in the room yesterday when I asked Mr. Weiss to do the calculation of the flow rate that would result from that equation if there were a pressure difference of 350 pounds between the two areas.

A Yes, I was here.

MR. PEARCE: If I may have just a moment, Mr. Chairman.

Q All right, Mr. Hueni, I'm having put up for us to look at a copy of Proponents Exhibit Number Twenty, which you testified to earlier. This is an updated version of an exhibit that we used in the March, 1988, hearing and I notice that at the time Gavilan began production there's approximately a 350 pound difference between the Gavilan and the pressures reported by Mr. Greer for the West Puerto Chiquito Mancos Pool, is that correct?

A Yes, sir.

Q Can you give me an estimate of how long that pressure difference is likely to have existed?

A Well, we see from the plot that there has been a pressure gradient prior to discovery of Gavilan and the direction between Gavilan and the pressure maintenance area that has existed since, well, really, almost since the initiation of production from the pressure maintenance area certainly been substantial since -- since about 1968, or so.

Q That's from 1968 up until --

A 1982.

Q -- 1982, and that's how many years?

A That would be fourteen years --

Q All right.

A -- where we'd have a substantial pressure gradient.

Q Do you have a calculator with you, sir?

A Yes, I do.

Q And do you recall the --

A Yeah, if I could -- if I could point out the points, the -- the pressure gradient is obviously substantial by the time the pressure in the Canada Ojitos Unit has declined down to the level that was measured in 1968. Obviously there was a pressure gradient even before that for essentially the full 20 years, but it's been -- it's obviously been fairly substantial since 1968,

Q All right, sir. Do you recall that Mr. Weiss calculated for me that there was about a 4300 barrel per day rate of flow under his assumptions?

A Well, see, I --

Q 350 pounds at the deltaP in that equation.

A Oh, okay. Okay, yes, I think that's

where I -- 450 pounds is --

Q Yes, but I asked him to assume 350.

A Right, okay, and his calculation was 4300 barrels a day.

Q Let's assume that that flow rate is 4300 pounds per day and would you multiply that out times 365 days for 14 years?

A Yes, sir.

Q And what's the result of that calculation?

A It shows that 22-million barrels of oil flowed across that one mile boundary between the B-32 and C-34 Well in that 14 years.

Q Mr. Hueni, do you believe that 22-million barrels of oil have flowed from the Gavilan to the West Puerto Chiquito since 1968?

A No, sir, I don't believe any has, really.

Q And do you think that's because his assumption that no barrier exists is incorrect, is that right?

A There is nothing that I have found in the study that we've done to indicate that there is a barrier present. Everything points the other direction.

Q Do you suspect that if the Gavilan

interest owners believed that 22-million barrels of oil had flowed to the West Puerto Chiquito they'd want it back?

A I suspect they would.

Q Thank you, sir.

MR. LEMAY: Mr. Lopez.

FURTHER DIRECT EXAMINATION

BY MR. LOPEZ:

Q Mr. Hueni, I think you said, and I think you misspoke just now. You said there's nothing that indicates that there's a barrier present, and you meant to state --

A I'm sorry. There is nothing to indicate there is not a barrier present. Everything indicates there is a barrier.

Q Thank you. Mr. Hueni, I refer to you what is our Exhibit Seven and I notice that it is the production history of the Gavilan Pool and the -- and the expansion area, proposed expansion area, and the pressure maintenance project in the Canada Ojitos.

Next I notice that since early 1983 the Canada Ojitos pressure maintenance project has been in a pretty steady, gradual rate of decline resulting to about 243 barrels of oil per day in 1988, is that correct?

A Yes, sir. In fact we have actually made some structural cross sections that show the wells in the pressure maintenance project, and what we see is that basically the production is coming out of the last row of down structure producers. All the other wells that are up structure are basically gassed out and been shut in.

Q I also notice that since early 1983 the Gavilan has increased up to almost 8000 barrels and depending on whether allowables were restricted or were allowed to produce under normal conditions, varied between 8000 and approximately 3000 barrels since 1986, is that correct?

A Yes, sir.

Q And do you see any affect on the rates at which Gavilan is produced on the performance of the pressure maintenance project?

A Not only do I not see any affect of the rates that Gavilan is produced on the pressure maintenance project, but I've not seen any affect that the change in Gavilan field pressures on the pressure maintenance project.

Q I do notice that there is an increase in the pressure maintenance production in mid-87 while Gavilan was producing at lower rates.

Is there any explanation for that increase in production at that time?

A Yes, sir. One of the wells that had

been shut in early in 1987 was returned to production. That was the well E-10, Canada Ojitos Unit Well E-10, and that well came on and initially produced I think in excess of 300 barrels a day with a fairly low GOR. Within the next several months the GOR increased substantially. The well's productivity declined off and I believe now by March again, that well was shut in.

So that little blip in the -- in the Canada Ojitos Unit pressure maintenance area production profile is the result of returning E-10 production for a short period of time.

MR. LOPEZ: No further questions.

MR. LEMAY: Thank you, Mr. Lopez.

Mr. Lund, do you have anything?

CROSS EXAMINATION

BY MR. KELLAHIN:

Q Mr. Hueni, I want to make sure I understand the way you have defined certain terms and phrases you've used either on the displays or in your testimony.

One of the first terms, and I will try to be consistent with your terms, is when you referred to the pressure maintenance area on the base map, Exhibit Number Five, it is that area shaded in tan that represents the Canada Ojito pressure maintenance project exclusive of the two rows of sections in the expansion area.

A Yes, sir.

Q And within that shaded area that's tan you've estimated there's approximately 50,000 acres.

A We've actually counted (unclear) and I think there's in excess of that. I think there's probably 52 or 53,000 acres but we've also reviewed other testimony, particularly by Mr. Greer, which has indicated that it consists of 50,000 acres.

Q Within this area do you have an estimate of what you consider to be the total volume of oil originally in place?

A We do not have an estimate that we have made independently. We've seen estimates that have been made, I think, by experts on behalf of Sun and BMG.

Q You've not made your own estimates.

A We have not made our own estimates, no.

Q When we look in the pressure maintenance area, do you have an estimate of what the original gas in place is?

A No, sir.

Q Do you have an estimate of -- for that project area of what the approximate gas in place is per acre?

A No, sir.

Q When we look at what you have used as the Gavilan Mancos Area, am I correct in understanding your displays consistently show not only the Gavilan Pool area but the two rows of expansion acreage that's displayed on Exhibit Number Five?

A Yes, sir.

Q When we take those two areas together, I believe your testimony was that there's approximately 47,200 acres in those two areas.

A Yes, sir.

Q Have you calculated what acreage is contained within the green area within the limits of the Gavilan Mancos Pool itself?

A I can tell you it's approximately 30,000 acres but I don't remember the exact number on that.

Q That was the number I've used, so we will be consistent. I had 30,000 plus. We'll use 30,000.

For the expansion area, what have you used for the acreage in the expansion area?

A Well, the difference, then, would be about 17,000 acres, I believe.

Q When we look at the expansion area,

using that 17,000 acres, approximately how much original oil in place is in that area?

A I don't know that it's possible to quantify individually within the combination of Gavilan and the Canada Ojitos Unit proposed expansion area exactly how much oil in place is under a given area. We have come to the conclusion that in combination those two have about 55-million barrels in place. We are aware of other estimates. I think one estimate by Sun will be shown to be about 64-million barrels. I think another area suggested by Mr. Greer's testimony based on his interference test values, are on the order of 1000 barrels per acre, and therefore, that would imply 47-million barrels in place.

So I see -- we have a 55-million barrel oil in place number. It's certainly right in the range of the numbers that -- that Mr. Greer and Sun seem to be using.

Q What I'm searching for is to make clear I understand when you talk about the Gavilan Mancos Area for the 55-million barrels of oil, it includes the expansion area.

A Yes, sir.

Q Do you have an estimate of what the original gas in place is for the Gavilan Mancos expansion area?

A We never identified the presence of any kind of gas cap in the Gavilan Mancos Area and therefore there was no free gas mentioned (unclear.)

Q Cam you estimate for us on a per acre basis what you anticipate to be the gas underlying a given acre?

A I'm not --

Q Either in solution or not in solution.

Q Well, I think we had a solution gas/oil ratio of in excess of 600 standard cubic feet per stock tank barrel initially in place and then whatever that would be multiplied by the oil in place.

Q When we look at display Number 26, Mr. Hueni, when we're identifying the West Puerto Chiquito Mancos Pressure Maintenance Area, you're using the 5,000 -- I'm sorry, the 50,000 acres that are identified in the tan area on display Number 5.

A Yes, sir.

Q When we're looking at the 11 wells, are those the 11 wells in the pressure maintenance project area?

A The 11 wells came out of the Four Corners Geological Society notebook. We corrected that to be 14 producers, 5 injectors for a total of 19 wells.

Q This does not include any of the wells in the expansion area.

A No, sir.

Q And it does not include any of the primary or secondary recovery out of the expansion area.

A There's no secondary recovery out of the expansion area.

Q In order to determine the amount of recovery per well within just the tan area of the project, can we take your recovery, estimated ultimate recovery in barrels of oil per acre, 161, multiply that by the 50,000, and then divide by the 19 wells to see what we're getting on a per well basis.

A I'm not sure if I understood that. Could you run back --

Q Sure.

A -- through your question again?

Q Be glad to. If I want to calculate what is the amount of production on a per well basis in the project area, can I simply take what you estimate to be the ultimate recovery, and I want to allocate that among the 19 wells, can I do that by simply taking this estimated ultimate recovery in barrels per acre, multiplying it by the acreage factor, and then dividing by the number of wells --

A Estimate --

Q -- and see what each well will ultimately produce?

A That would be one way of doing it. The other way of doing it would be basically to take the recovery through December of '87 and divide by 19 wells.

Q My lawyer's calculator shows me that that's about 424,000 barrels of oil of ultimate recovery estimated for each of the 19 wells.

A It very well could be. I haven't (unclear) but that doesn't sound unreasonable to me.

Q Are there any of the other reservoirs that you've displayed on 26 that have that rate of recovery per well?

A No, sir, I don't think so.

Q Am I correct in understanding your analysis of the information displayed on Exhibit Number Twenty-five that in drawing a comparison you have made that comparison between the Gavilan Mancos Area, which includes Gavilan Mancos and the expansion area, and contrasted that to the pressure maintenance project which shows the pressure maintenance project exclusive of the expansion area?

A Yes, sir, because we don't believe that the proposed expansion area is really part of the pressure maintenance project, so we've included that in the Gavilan Mancos Area calculation.

Q When we look at your display Number Six, Mr. Hueni, again what you're comparing is the Gavilan Mancos Area, which includes the Gavilan Mancos Pool, the expansion area, and contrasting that to the pressure maintenance project that's identified as tan acreage.

A Which exhibit are you referring to?

Q Exhibit Number Six. Do you have your exhibit book, sir?

A I think Exhibit Number Six is strictly data on the Gavilan Mancos Pool and the Canada Ojitos Unit proposed expansion area. It doesn't contrast anything, though --

Q I misspoke.

A -- as far as I'm concerned.

Q I misspoke. It does include the expansion area in this display.

A Yes, it does.

Q And when we look at Number Seven it is, that is the one that contrasts the pressure maintenance project with Gavilan and the expansion area.

A Yes, sir.

Q Again, on Exhibit Eight, when we look at Exhibit Eight, we're looking at Gavilan plus the expansion area?

A Yeah. I think once again it does need

to be pointed out that we have used wells only as of July, 1987, in certain of these exhibits to try and keep the comparison on a uniform well basis.

Q Is your analysis of the characteristics of the reservoir and how it's being produced predicated on the principle point that there must be an effective pressure communication barrier between the project area and the expansion area?

A Well, there are two -- two parts to our analysis, obviously. One is that -- is that high rates reduce the efficiency with which gas is utilized -- I'm sorry -- restricted rates reduce the efficiency with which gas is utilized, whereas normal rates tend to maximize the efficiency.

The second part of that, though, is that yes, we do believe that there is a barrier between those two portions of the Canada Ojitos Unit.

Q The second principal point upon which you have built your study, made your conclusions, and made your recommendations, is the presence of an effective pressure communication barrier between the project area and the expansion area, and second of all, that we have a reservoir in Gavilan side that works as an effective dual porosity reservoir.

A I think that's a probative summary, yes.

Q Those are the two fundamental blocks upon which you have then reached your conclusion.

A Well, those are -- those are two of the fundamental blocks.

Q Have you attempted to construct any displays similar to the ones, say, for Exhibit Number Seven, in which you have taken the production from the expansion area, and put it with the pressure maintenance project production?

A No, sir. No, sir, we haven't, because very simply, we find no evidence to indicate that those should be communicated.

Q Back to the barrier.

A Back to the barrier.

Q If the barrier, in fact, is an effective barrier and if, in fact, we have a dual porosity reservoir that has effective matrix contribution, then your analysis is going to be right.

A Yes.

Q Your conclusions for Exhibit Twenty-five, your economic projections of the amount of loss of oil and money, are predicated upon those two principles.

A No, sir, I don't think that's necessarily true. The amount of -- I'm sorry, the projections on which figure, did you ask, Twenty-five?

Q Yes, sir.

A For the Canada Ojitos Unit I think that is fairly well -- for the pressure maintenance area that's fairly well substantiated by -- by actual performance and the decline projection of existing performance.

For the case of the Gavilan Area, that's once again based on our simulation study, which basically treated the Gavilan Area and Canada Ojitos Unit proposed expansion area as a single -- as a single entity.

Q When we look at Exhibits Nineteen A and B, those estimates of physical waste and the calculation of lost reserves are predicated on this barrier existing as a matter of fact, between the project area and the expansion area.

A Not entirely. They're predicated more on a dual porosity type system, that if you have -- if you have a high permeability fracture system surrounded by something that's lower permeability, that you have to draw the pressure down in the high permeability fracture system in order to get flow out of the low permeability regions.

Q These calculations take into considera- tion your estimate of lost reserves for the expansion area, do they not?

A Yes, they do.

A And they attribute it to the Gavilan

Mancos Area.

A We refer to the proposed expansion area as part of the Gavilan Mancos Area because we don't see the current boundary as being (unclear) physical boundary.

Q if the boundary -- the barrier is not there, the expansion acreage is put in the Unit, and you do not have effective dual porosity contribution in the reservoir of the matrix, then these numbers are going to significantly change.

A Well, I think our study says that that's just not the case.

Q I understand. But if those are not the case, then these numbers are all going to change.

A Well, if we're not right, we're not right.

Q You had some -- you had a display 21 and perhaps we could put that one up, in which you have re-interpreted Mr. Greer's rainbow map.

I want to examine with you, Mr. Hueni, what we can determine to be the pressure gradients across the barrier as depicted on Exhibit Number 21, sir. If we look at the display, the farthest -- they look like circles to me, I'll agree with you there, I think they're circles -- the farthest brown circle to the right is approximately at what footage distance on the scale?

A Well, it looks like it's about -- somewhere around, maybe, 10,200 to 10,400 feet.

Q I used 10,200, is that close enough?

A That's fine with me.

Q That well is going to be which well on the rainbow map?

A I believe that's going to be the A-20 Well.

Q When we move across the barrier you've placed on the exhibit and we come to the first green circle after the barrier, approximately where is that on the bottom distance footage scale?

A I guess that would be at about 16,400, yes, around 16,400.

Q And when we look at that nearest well to the barrier, what well, or two wells, are we looking at?

A It looks to me like that's probably Well E-10 and I would think that it's Well L-27, as well.

Q Thank you. You told me that footage distance on the lower scale for the green wells was what, sir? About 17,000?

A I believe -- no, I said it was about 16,400, 16,400.

Q We can determine the pressure differential, then, across that distance by simply taking the difference in the upper pressure of 11 -- 1150 pounds and the 800 pounds found in the expansion area, which gives you 350 pounds, we can simply take that and divide it by the distance and show what the pressure gradient is across that barrier.

A Well, I don't think that would be -- that wouldn't be a fair representation or our position, because our position is that there is a barrier and there is not a gradient across that barrier. It is a pressure on one side and a pressure on the other side. There is not a pressure gradient through that barrier that causes flow.

Q Have you attempted to determine whether or not you could plot what occurs in the Gavilan Mancos Pool itself on a display like this?

A We -- we have made isobaric maps of the Gavilan Mancos Pool pressures, which will, I think, be presented later.

Q Help me find that exhibit that showed your projections using the computer modeling from March of 1987, Mr. Hueni. I believe they're Exhibits Twenty-four, are they not?

A Twenty-four, that's correct.

Q When you have looked at the model that you constructed for this analysis, my recollection was that you used a dual porosity model.

A Yes, that's correct.

Q Did you attempt to update that model since the last hearing?

A No, sir.

Q Have you changed any of the parameters and made new projections with that model?

A No, sir.

Q What you have then done in this display is simply taken the results of the simulation study and superimposed, then, what you have seen with actual field performance in the Gavilan Area.

A What we have done is we have scaled up the model results. The model results were a cross section for a typical portion of the field and it's necessary, then to scale up that model for the whole field.

What you see there is a scaling up to -- of the model results to the full field -- to a full field basis.

Q Have you attempted to use your dual porosity model to further simulate the reservoir based upon the production test results that we obtained in '87 and early '88?

A No, sir. We think the work we did beforehand is basically -- is pretty doggoned consistent with what's actually happened.

Q Let me have you look with me, Mr. Hueni, at the conclusions you made in the March, 1987, hearing, and I have made a photocopy of your summary and recommendations from -- from that exhibit book.

Am I correct in understanding that you've told us yesterday and today that you see a reservoir based upon the tests, that at higher rates we see a reservoir that is not producing more gas than at lower rates but at higher rates we're recovering more oil?

A It certainly appears from the data that we've seen that -- that as the oil rate is restricted, the gas rate tends to stay up, and so we continue to produce maybe not the same, absolute volume of gas, because we have to shut the wells in periodically because of the allowable, but when those wells are producing at capacity, the rate is still the same rate as it -- as it was before we -- we had the restricted rate; we just had less oil coming in at that rate.

Q Do you now see a reservoir that is rate sensitive so that at higher rates we get more oil?

A Yes, we do.

Q Back in March of '87 my recollection is of your work, is that you told us we had a reservoir that was was not going to be rate sensitive.

A Yes, that's what we indicated on our

last exhibit, and that was the one thing that had really changed as a result of this Commission order testing period, that's correct.

Q When we look at the first page of the summary of recommendations, in the last line of the second paragraph your estimate of the original oil in place for Gavilan Mancos, 55-million stock tank barrels. You've not changed that estimate?

A No, sir, but that is the -- by Gavilan Mancos Pool we meant to imply also the portion of the Canada Unit that was in pressure communication with the Gavilan Mancos Pool itself.

Q Do you still hold with the opinion beginning at the first line of the second -- I'm sorry, the third paragraph of that page, that current primary depletion is 5.7 percent of the ultimate -- of the oil in place?

A Well, we've made some oil since the date of this report, so I think it would have had to gone up a little bit.

Q Do you still expect the ultimate primary recovery will amount to 17 percent of the oil in place?

A I think that's about correct.

Q The next line is not any longer correct. It said this recovery is not sensitive to the producing rates within the range of possible producing rates.

A That is correct.

Q We've found that that's not true.

A We've found as a result of our testing that that -- that's not true.

Q Is it still your opinion where you say on the last sentence of that paragraph, on the other hand low pressure gas injection following depletion of the matrix may be economically viable but will not be required for approximately four or five years?

A No, sir, I think that our opinion is now that low pressure gas injection is going to be economically viable; that there is nothing to indicate that we will have any type of sweep of the lower permeability portion of the reservoir, because there's no -- whereas we've seen through this inverse rate sensitivity, we've seen this imbibition effect taking place and I think we -- we are going to see that with gas injection, so we have -- do not believe that low pressure gas injection is going to be viable.

Q The inverse rate sensitivity that you now see as the explanation for what's occurring in the reservoir with these tests, that was not a result that you projected in March of 1987.

A We don't see the inverse rate sensitivity as an explanation. We see the imbibition behavior of a dual porosity system as the explanation.

The rate sensitivity is simply a demonstrated phenomenon, but we did not fully expect that at the time of the March, 1987, hearing.

Q One of the bases for your support that there is an effective pressure communication barrier between Gavilan Mancos and the expansion area versus West Puerto Chiquito Project Area, was your Exhibit Number Nineteen, I believe, for today's hearing, and that was an update of Exhibit Nine from the pressure maintenance hearing in March of this year?

A Yes, sir.

Q Let me have a moment to find that.

Let me correct myself, Mr. Hueni, it's in fact Exhibit Twenty for today's hearing.

Am I correct in understanding that this is an update of Exhibit Nine from the pressure maintenance hearing that we conducted in March of this year?

A Yes, that is.

Q Could you describe for me in what ways you have updated the display?

A Yes, sir, we have -- we have placed on the display what we consider to be the field average pressure in March of 1988. As I mentioned before, there are some pressures that are higher than field average when corhearing that we conducted in March of this year?

A Yes, that is.

Q Could you describe for me in what ways you have updated the display?

A Yes, sir, we have -- we have placed on the display what we consider to be the field average pressure in March of 1988. As I mentioned before, there are some pressures that are higher than field average when corrected to this common datum; there are some pressures that are below the field average when corrected to this datum. This is what we believe is the field average trend and we've indicated that on -- on the exhibit.

Q All right, when we look at the display and we look at that portion of the display in the upper right corner, what you're telling me is you've added the interpretation down here which ends at March of 1988, this dark black line, you've added that?

A Yes, sir.

Q Other than that you've made no changes on this display.

A I think we've maybe put on an additional well, I think, in 1984 on the bottom of the display. It's just another point that we had -- had left out that showed a fairly high pressure in the -- in the Gavilan Area. It's on the lower display right above the Gavilan curve. It's a dot that's, I can't remember, I think it may be a pressure off the Native Son Well.

Q When we --

A And it shows a little bit higher pressure than what we were interpreting as the fieldwide average pressure at discovery.

Q When we look at the bottom portion of the display and we see the Canada Ojitos Unit Well 14, it's called the C-34 Well, back down in the end of 1970, that point on that display represents a measured pressure for that well?

A It represents a measured pressure in the oil zone. Yes, that's correct.

Q When we continue along that line, there is a dashed -- the line becomes dashed and we get all the way over to the end of 1987 where we pick up a pressure test on that same well, the C-34 Well?

A Yes, sir.

Q In between those points on the dashed line in 1982, then we have the Gavilan coming into existence and production.

A Yes, sir.

Q Do we have a corresponding bottom hole pressure in the project area that corresponds to when Gavilan was first produced?

A The -- the dashed line that we've shown on there is not based on what we can see as measured pressures in the Canada Ojitos Unit that we had available to us.

Now we took basically information that Mr. Greer had presented previously. He projected a trend in pressures as well. He has referred in previous testimony about a continual pressure decline in the pressure maintenance area. We assume that he probably has some additional pressures on which he bases that.

We have also reviewed Mr. -- Dr. Lee's study, in which he modeled the Canada Ojitos Unit pressure maintenance project, and he showed a decline through that period, as well.

So basically all of our projections are consistent with what -- what's been said by Dr. Lee, by Mr. Greer, and based on the available data that we have, as well as the trend in pressure decline that was observed back in '67-'68 matched up, so -- but in terms of having a pressure in the Canada Ojitos Unit, no, we were not -- did not have a pressure as such.

Q So we don't have a measured pressure to determine exactly where this dashed line is going to be at the time that Gavilan was discovered.

A No, sir, I -- just what he had -- followed what everybody else has had.

Q When we get our first measured pressure in the Gavilan Area, we're getting it from the Native Son No. 1 Well?

A Well, the measured pressure in Gavilan, the initial pressure in Gavilan is -- within a certain range of pressures, have been interpretive, because some of the very earliest pressures were on wells that were commingled with the Dakota. We didn't necessarily have good -- what we consider good, valid pressures.

What we have done is to plot pressure versus cumulative production for all the wells and to back extrapolate that curve to a value of about 1800 psi as the initial Gavilan pressure.

Q You told us awhile ago that it was of importance to you that there was a difference between the Gavilan pressure and the Unit pressure, and it was a question of where it fell, above or below a certain line.

A I think I said -- one of the things that I said is that with respect to this exhibit, that the fact that -- that all evidence indicates that Gavilan operates independently of Canada Ojitos in a pressure maintenance area and that this line that initially starts off above the -- the pressures for the pressure maintenance area and then subsequently falls below that line, and, well, I think that -- that is certainly significant.

Q It's approximately 350 pounds, as Mr. Douglass wrote on this display Number Twenty.

A That's the difference between the Gavilan area pressure and the (unclear).

Q For you as an engineer at what point does that pressure differential become low enough that you're no longer confident that you've got pressure separation between the two areas?

A I don't think that I am going to give you a value on that. I think you -- when you look at separation in an area, you have to look at all of the data. You have to look at the pressure trend. You have to look at the affects of production, one side on the other side. You have to look at any kind of pressure tests that have been run, pressure build-up or interference tests that have been run, and it's -- it's a collective judgement; it is not a judgement made on one single piece of data.

Q Rolling that all into your position, what would we might expect for a range of difference here in pressures at which you're no longer confident that you're going to have separation in the two areas?

A I don't have a number to give you.

Q 50 pounds or 100 pounds?

A I -- I just don't have that -- in part it -- you look at the pressure gradient. You look at the pressure gradient as measured on Mr. Greer's rainbow map. From one side of that area to the other side of the area, there is essentially no pressure gradient on either side and then there is a discontinuity in pressure, and so if that discontinuity in pressure existed, even though the pressure difference wasn't very -- very great, that would still be an indication of a barrier.

Q When you looked at the Gavilan Pool itself, within Gavilan exclusive of the expansion area, what were the ranges of pressure gradients found in Gavilan?

A Well, I think you can see, we have not on our upper panel of that exhibit, of the Exhibit Number Twenty, we have several of the individual wells shown in the -- in the Gavilan Mancos Area plotted.

There are -- there are additional wells that were not plotted on that exhibit because they were not necessarily wells that were in this area of -- close to the barrier in the proposed expansion area. But I think you see some -- obviously, some range in pressures there. As I stated before, we have drawn some isobaric maps of the Gavilan Area and some current pressures and there is a pressure difference between different areas.

Q Have you attempted to quantify what specific wells or a number of wells that are going to be benefitted with a higher allowable at the 2000-to-1 gas/oil ratio?

A Yes, but we've never done that. We've never looked at specific wells in that light.

Q Have you attempted to forecast how long we would have to leave the gas/oil limitation at 2000-to-1 before we would have to increase that?

A No, sir, I'm not sure that I can answer that without doing some additional study.

Q Am I correct in understanding that we're going to have, at whatever allowable rate, we're going to have climbing gas/oil ratios in the reservoir as we deplete the reservoir?

A Well, you sure didn't when you -- when you increased the rate previously. The gas/oil ratios went down. They didn't go up.

Q Am I correct in understanding, though, the reservoir is going to reach a point at ultimate depletion where these gas/oil ratios are going to climb. That's what's going to stop production, is it not?

A No, I think eventually, basically you're going to drain as much oil as you can out of the low permeability sections. The pressure will have gone down substantially and you'll lose deliverability on the individual wells. Your gas direction will be substantial. It's just -- I think our point is it's better to get the oil with the gas than just get the gas.

Q I'll take you back to your conclusions in August of 1986, Mr. Hueni. Those are the -- these are the '86 conclusions.

These were your conclusions from the August '86 hearing on the producing rates in the Gavilan Mancos Area, Mr. Hueni?

A Yes, I believe they are. That's correct.

Q Let me direct your attention to conclusion number three. The last portion of that conclusion said at that time you concluded that we have the presence of an effective secondary gas cap expansion mechanism.

A Yes, sir.

Q Is that your conclusion now?

A No, sir.

Q When we look at number eleven on the second page, your study was then that there is a comparison of predicted solution gas drive performance to actual data indicates the reservoir is not a solution gas drive reservoir but is behaving as a gas cap expansion reservoir.

A Yes, sir.

@ That was your conclusion then?

A Yes, sir, that -- in the August, 1986, study, in our investigations at that time we -- one of the things that I think we accepted at that time without doing a great deal of investigation, is that we hadn't really considered the dual porosity aspect of this particular reservoir.

That came as a result of forming the study group reviewing all the data and doing a detailed study.

What we had concluded in the 1986 study was that -- once again, it's the same conclusion we have now -- the gas and oil segregate vertically at a point in the reservoir. In other words, if you're watching production a lot, you're going to see gas, then you're going to see oil, and with kind of performance, basically you get some sort of gas contact moving vertically down through the formation at a point in the reservoir, and so what happens is, as in contrast to the solution gas drive, you get a smaller increase in gas/oil ratio.

We expect to see that as well in -- in the dual porosity system that we have now, and in fact that is the reason that our projections never go to a really gas/oil ratio.

But within the dual -- within the low

permeability areas now, what we see is we see that -- that that area is tight. Basically it is a solution gas drive reservoir within that portion of the field, but it feeds into a major fracture system where gas and oil segregate such that the gas is always at a point in the reservoir above the oil, and that's confirmed by essentially production tests and production logs uniformly through the field.

So our '86 study has been modified to include the dual porosity concept and that is the reason these conclusions have changed.

Q And when you got to the March of 1987 conclusions that I handed you awhile ago, in that summary as a predicate to the summaries, you had, in fact, incorporated by then the hypothesis that we had a dual -- dual porosity reservoir and it was operating as a dual porosity reservoir.

A Yes, sir.

Q And having incorporated that into your study in March of '87, one of the forecasts that you made in that study was that we would not see a rate sensitive reservoir.

A That is correct.

Q And now you tell us that we see a rate sensitive reservoir where at higher rates we get more oil with the same amount of gas than we would if (inaudible.)

A The one thing that we didn't have in the March, 1987, study, we didn't have any kind of imbibition, imbibition behavior built in to the system and basically we used -- our model was based on what we saw as capacity type production and modeled on historical capacity type production. As a -- as a consequence when we reduced our rate the imbibition effects which we hadn't seen up to that time became apparent and it's pretty apparent that that's what is happening out there at this point in time and it is making for an inefficient use of reservoir energy with restricted rates.

Q Am I correct in understanding, Mr. Hueni, that it's absolutely essential for your analysis to be correct that we have a dual porosity reservoir where the matrix is effectively contributing to ultimate recovery and we must have an effective pressure communication barrier between the project area the expansion area?

A You're right in saying that those are the -- two of the very major results of our analysis, that's correct.

Q And if either one or both of those are not right, then your analysis and conclusions are wrong.

A That is not -- when you say either one of them is not right, that's not fully correct.

For example, if we were not right about

the barrier, the inverse rate sensitivity is still a correct conclusion, and they're not necessarily dependent on each other.

Q Thank you, Mr. Hueni.

MR. LEMAY: Mr. Carr?

FURTHER DIRECT EXAMINATION

BY MR. CARR:

Q Mr. Hueni, I believe you recommended that the boundary between Canada Ojitos and the Gavilan Pool be moved as recommended by Mesa Grande in Case 9412, is that correct?

A Yes, sir.

Q If we move that boundary two sections to the east, it isn't going to change the boundary between the unit and the production in the Gavilan to the west, is it?

A I'm not sure if I understand what you mean, it's not going to change the boundary.

Q I mean the boundary of the unit will remain, isn't that right?

A As I assume, I really don't know what the mechanics are of moving boundaries.

Q Well, what was the basis for your recommendation? Is it simply to make a physical boundary and a definition of pools coincide?

A Yes, sir. We believe that that -- that that movement of the boundary is necessary so that that Gavilan Mancos Pool operates as a single unit that is -- that's its true reservoir size and that's (unclear).

Q It wasn't your testimony that that would have any affect on the existing unit boundary. Is that right?

A I don't know the mechanics of how that boundary would be moved.

It's simply from a reservoir standpoint that we have a geologic engineering boundary that exists between the pressure maintenance project and the proposed expansion area.

Q But it wasn't the purpose of making your recommendation to tell this Commission that moving that boundary resolves any questions that exist between the unit and production off to the west of it.

That -- moving that boundary doesn't necessarily decide that question. That's not what you were telling the Commission, is it?

A I'm afraid that I may be missing your point. I'm not saying that it --

Q Did you -- maybe I can make it clear. In moving the -- recommending that the boundary be moved, you were doing nothing more than moving to what you perceive a physical boundary, the current definition of boundary between these pools.

A Yes, that's correct.

Q You were not trying to comment on the effect this might have on whether pressure maintenance was extended or what it would do on the unit boundary, or any of those other things, you're speaking only from an engineering point of view.

A We're saying that the physical boundary should be located two tiers of sections to the east.

Q And that's because you perceive a barrier to be there.

A Yes, we believe the barrier is there.

Q And your recommendation is not to be perceived, or you weren't trying to hold that out as some sort of "solve all" for all of -- or resolution of all the questions that are between the parties in this proceeding.

A We're saying that's simply a physical boundary that's located in that position.

Q That's a physical boundary you see, and if Mr. Weiss is right, then, of course, again you'd be wrong and he'd be right and we'd be back to where you've been talking to Mr. Kellahin.

Q Unfortunately, I think we have a lot

more data that Mr. Weiss does regarding the presence of that boundary.

Q But if you're wrong, you're wrong.

A We're not wrong.

Q Now, as an expert witness, let's suppose for a moment you were wrong; just suppose that. If that is the case, if we go to your Exhibit Number Seven, and there is no barrier there, it wouldn't be appropriate, would it, to credit the production from the expansion zone with the remainder of the Gavilan and remove it from the West Puerto Chiquito Pool, if the boundary is not there?

A Well, first, the boundary is -- is there, and --

Q Well, that's your opinion, but you're an expert and I'm asking --

MR. DOUGLASS: Well, I -- I'm --

Q -- you to assume that it isn't there.

MR. DOUGLASS: -- sorry, I don't believe the witness had finished his answer, Mr. Chairman, and I'm sure that Mr. Carr wants him to finish his answer before he starts asking the next question.

MR. LEMAY: (Not clearly understood) for the witness to answer Mr. Carr's question and if it wasn't answered correctly, Mr. Carr can rephrase the question.

A The -- first we believe the boundary is there.

Second, that we would still want to see the Gavilan -- or the Canada Ojitos Unit and the proposed expansion area treated in the same fashion as we would treat the Gavilan Mancos Area, because we know there is a substantial pressure difference between the pressure maintenance area and the proposed expansion area.

So -- and we know the proposed expansion area is more Gavilan-like than it is pressure maintenance-like.

Q Mr. Hueni, let's look at Exhibit Number Seven and take that out, please.

Mr. Hueni, the top green line is the production from Gavilan plus the expansion area, is that correct?

A Yes, that's correct.

Q And if you didn't include the expansion area, that line would come down, would it not?

A Yes, it would.

Q Have you calculated how much that line would have to come down if you didn't include production from the expansion area?

A Well, I think we quoted in our -- in one of our other exhibits, that by March of 1988 the expansion area with current restricted allowables and the effect on GOR's, the expansion area makes about 1700 barrels of oil a day, representing about 54 percent of the production in March.

Q And you would have to, if you took that out of the Gavilan and put it back in West Puerto Chiquito, bring that top line down.

A We don't believe that that would be a physically realistic representation of how reservoirs operate. because the -- we're talking about adding it to a pressure maintenance project, an area that is undergoing primary depletion.

Q Well, I'm just asking you to look at this line and tell me that if you put the production that is now within the Canada Ojitos Unit as defined by this Commission and you took it out of the green line that is the Gavilan representation, wouldn't it bring that Gavilan line down?

A Well, certainly, it has to bring it down.

Q And you would -- if you put it in the Canada Ojitos Unit, wouldn't it bring the bottom line up?

A Certainly, it has to bring the bottom line up.

Q And if you attributed production to the various pools as those are defined today, this graph would look very different, wouldn't it?

A If you did it that way, yes, the graph would look different but it would not be technically correct.

Q Assuming your interpretation of the barrier existing there having a proper division between the pools (inaudible).

A It doesn't even have to assume the barrier. Basically it just has to look at the pressure -- the pressure relationship between Gavilan and the proposed expansion area versus the pressure relationships in the pressure maintenance area.

Q I'd like to go to Exhibit Number Nine.

As I see Exhibit Number Nine, what this is designed to show is that when oil production came down gas/oil ratios went up.

A Yes, that's correct.

Q And how many wells were included in Exhibit Number Nine?

A To tell you the truth, I'm not sure whether we had just the wells that were on production in July, 1987, or whether we have all the wells that were on production through March of 1988, but it is intended to portray all the wells in the -- that were producing at these points in time in the Gavilan Mancos Pool, as well as the proposed expansion area.

Q Now, when you do this you include every well reaching these averages?

A Yes. We simply took the data off of the tabulation of production at a given point in time for the oil and for the gas and then calculated the field gas/oil ratio and plotted that versus oil production.

Q And if you found a well in which the oil rate went up and the gas/oil ratio also went up, it would be included in that exhibit?

A Yes, it wouldn't matter which direction the individual wells had gone.

Q When you reviewed this did you find wells where the oil rate went up at the same time the gas/oil ratio did?

A We found wells similar to what Mr. Weiss did. There appeared to be -- appeared to be difficult to establish a relationship. We found, however, the majority of the wells did have a relationship that low rates were associated with high gas/oil ratios.

Q It would be true, though, that almost half of the wells displayed different characteristics although maybe not to the same degree.

A Well, they explained some that you would have a difficult time if you wanted to do it statistically, simply correlating them.

Q If I can go to Exhibit Eleven, I marked it Eleven-A but I think that's just because you had more than one graph. I don't think it makes any difference which ones we use. I'd like to look -- perhaps the first one. And what I see here is, if I'm correct and understand your testimony, that the oil production is restricted, and let me ask you this. Is it restricted because of the oil allowable or because of the oil allowable in conjunction with the gas/oil ratio?

A It's restricted by the amount of gas that's allowed to be produced.

Q And so if, in fact, you are to increase production, if I understand your testimony, what is needed is either authority to produce more gas or a higher gas/oil ratio, is that what -- is that a fair statement?

A In order to maximize recovery from this field you basically have to go on a capacity allowable to draw down the lower permeability sections of the reservoir for maximum results.

Q And you'd have to really focus on the gas in terms of dealing with this problem, isn't that a fair statement?

A I don't know anything about focus on the gas.

Q It's not the oil allowable that's the problem, it's the oil -- it's the gas restriction coupled with that allowable, with that oil allowable.

A Well, it's -- it's -- yes, in order to calculate the oil allowable you take the allowed amount of gas and find out the gas/oil ratio and that tells you how much oil you can make, but really, what happens is that the gas stays fairly constant. It just happens that the gas-oil ratio seems to soar and as a result it's -- it's not a proportional reduction in the amount of gas you can take out because with the increase in gas/oil ratio it overly restricts the oil production.

Q So what we're really got to address is the problems that come from this, either the gas/oil ratio or the restricted gas production rates, isn't that fair to say?

A Well, we need to lift the amount of gas production in an absolute sense that a given well can make so that its gas/oil ratio will go down so that it's oil rate will come up, and so that we'll maximize recovery and we'll utilize the gas energy to the maximum possible.

Q Isn't the real problem we're trying to deal with here, though, today is the restriction of the gas volumes that can be produced because of the gas/oil ratios?

A Well, and it flows through to the oil volumes.

Q That's right. We need to focus on the gas production if we're trying to resolve this problem, isn't that right?

A Well, I think we said that by taking out lower amounts of gas relative to the amount of -- what we'd like to do is take out as little gas as we -- we need to to take out a barrel of oil. That's -- that's where efficiency comes in.

Q And at the present time the gas restrictions are the problem.

A The gas restrictions mean that we can't generate as much pressure drawdown into the formation which means basically only gas flows and basically bleeds out and -- and we lose our pressure that much, so we need to increase our -- our allowable gas production in order to achieve higher oil recovery in acreage production.

Q Let's pull Exhibit Number Fourteen here.

Let's go to Exhibit Number Fifteen. I have no questions on Fourteen.

If I understand what this shows, in the first graph, we've got a comparison of production from the Mallon 1-8, the Canada Ojitos E-6, is that right? On Exhibit Fifteen, that you've talked about.

A Yes, it's a comparison of the Howard Federal 1-8 with the Canada Ojitos Unit E-6.

Q And this is March '88 production.

A It is based on the March, 1988, gas/oil ratio and then it is a calculated allowable rate. The well may have produced a little bit different from that, but this is what it's allowable production would be.

Q And the Howard 1-8 has a gas/oil ratio of 4200, right?

A Yes, that's correct.

Q Canada Ojitos Well, 5240.

A Yes. sir.

Q It doesn't really make any difference whether or not these wells are one in Canada Ojitos or -- and one in Gavilan or both in Gavilan, both in Canada Ojitos, isn't that right?

A I'm not sure if I --

Q Doesn't this --

A -- make any difference --

Q Okay, what --

A -- they're just two wells in the Gavilan Pool.

Q And -- and the fact of the matter is

that all this really shows in the first graph is just the effective gas/oil ratio, isn't that true?

A It shows the effect of the gas limit and the observed gas/oil ratio.

Q And in looking at this reservoir did you also consider other wells offsetting the Howard Federal 1-8?

A We made, obviously, two bar graphs we've presented and one is the western two tiers of sections compared to the eastern -- I'm sorry, the eastern two tiers of Gavilan sections compared with the western two tiers of Canada Ojitos Unit sections.

And then we made this comparison for these two wells because they are so closely spaced and so otherwise identical.

We did do this for other wells. We did this for the prior hearing and I don't know that we ever used any of that. We didn't upgrade it for this hearing.

Q If you'd look at, say, the Hixon Development Tapacitos No. 4 Well to the north, would you accept, subject to check, that it has a gas/oil ratio of 5118?

A I don't know what it's gas/oil ratio is; perhaps that's correct.

Q And that with that gas/oil ratio during March it produced 54 barrels a day.

A I think that's what it's allowable rate would be.

Q And so, in essence, what this graph does show is just how the gas/oil ratio is functioning, isn't that right?

A Yes, that's correct.

Q And then we go to the second graph and that is showing the effect of the gas injection credit.

A Yes, it is.

Q And the gas injection credit, in your opinion, is inappropriate because of the barrier.

A Yes, sir, that's correct. We don't see that the gas injection is going to help the proposed expansion area in any fashion.

Q And it is because of this barrier that you see crossing the reservoir.

A We do not see -- we did not see any gas moving across that, receiving pressure support.

Q And that is the reason that you think the gas injection credit is inappropriate.

A That is certainly one of the reasons.

I think the second reason is that it totally distorts the production balance between the Gavilan side and the Canada Ojitos side.

MR. CARR: That's all I have.

MR. LEMAY: Thank you, Mr. Carr.

We'll adjourn for lunch and reconvene at 1:30.

(Thereupon the noon recess was taken.)

MR. LEMAY: The hearing will come to order and we'll continue with the Gavilan - West Puerto Chiquito Mancos hearing.

When we adjourned for lunch I think Mr. Carr was cross examining the witness. Are you completed, Mr. Carr?

MR. CARR: I am. I think Mr. Kellahin has a couple of other questions. If he can do that, then I think we'll be finished.

MR. LEMAY: Fine. Mr. Kellahin, do you --

MR. KELLAHIN: Mr. Chairman, a housekeeping chore.

Awhile ago I showed Mr. Hueni copies of summary sheets and conclusions from the two prior hearings.

Perhaps I'm misinformed, but I thought perhaps we could not confuse the record by marking them as separate exhibits for this hearing. It's obvious where they came from . We've incorporated the records from those past cases.

If there's no objection, I'd propose not to mark them as exhibits for this case.

MR. LEMAY: I see no reason unless opposing counsel --

MR. DOUGLASS: That's fine with us.

MR. LEMAY: -- would like to mark them. They're referred to as part of the record and this testimony concerning them is in the record here, so --

MR. KELLAHIN; In reviewing my notes during the lunch hour, Mr. Chairman, there was some issues that I would like Mr. Hueni to clarify for me, and I'll tell you, they won't clarity anything for me whatever you say, but I have some engineering experts that would like to make sure that I have not misunderstood or that you have not been misunderstood.

RECROSS EXAMINATION

BY MR. KELLAHIN:

Q I did ask you this morning some questions about the model, whether or not from the '87 modeling at the March hearing to now, whether or not you had changed that model, and I believe your answer was that you had not changed the parameters that went into that model.

A That is correct. We have not rerun the model.

Q Am I also correct in remembering from the March, '87 hearing that that model did not have a factor put into it whereby it could model the capability of the matrix to imbibe the oil?

A Yes, sir, that's -- that's correct. Our model that we made in -- in early 1987 was a dual porosity model. We did not include any capillary forces which are another -- capillary forces and imbibition are related. We did not do that because, once again, and I think as we've said before, what we mean by matrix, I think people have basically misquoted us on this. We mean simply that the reservoir is heterogeneous. It has a major fracture system. It has lower permeability rock. The less intense fractures, it could be matrix porosity itself and it could be microfractures. We have -- we have looked at core material that is reflective primarily of matrix rock itself. We do not have any kind of laboratory tests that reflect the composite behavior of the remainder of what we call matrix. So we don't have any capillary pressure characteristics that -- that reflect that segment of the reservoir that contains, in our estimation, 90 percent of the oil.

In doing our simulation study we matched performance in the absence of capillary pressure. That meant that we were basically matching performance under current operations and we were adjusting matrix permeability (unclear). We did not have capillary pressure in there because we had no physical basis on which to base a capillary pressure curve.

We now see as a result of the Commission order testing, that the capillary pressure imbibition behavior of the rocks is significant and its significance is that in the absence of high rates it will -- we will end up -- in the absence of higher oil rates and higher pressure differential, we will end up just bleeding gas from the rocks and not recovering oil along with that. That is a capillary pressure phenomenon, imbibition type phenomenon, (unclear).

Q When we talk about the oil moving out of the matrix, do we have a calculation or a method of measurement of the flow of that oil out of the matrix?

A No, sir, we haven't relied on calculations. We've relied strictly on observations in this case.

Q When we talk about the core information, I guess I'm not clear on whether or not in examining that information, are you telling me you're able to pump fluid into the matrix and thereby you know you can extract it from the matrix?

A We are talking about the matrix porosity, the secondary porosity, that was present in the core material that we looked at.

We looked at a, particularly a core plug that was free of anything that we could identify as visible fractures. Fluid was injected into that far in excess of anything we could see as -- as potential fracture volume; therefore, fluid had to enter into some matrix core space.

Inasmuch as we can inject fluid into it, at least for that period of time that the reservoir fluid is a single phase fluid, there's no doubt that it can come right back out.

Q And the measurement by which you pumped the fluid into the core was using the Mallon Davis core, the Mallon Davis core? Or was this the Mobil Lindrith D-37 Well?

A We were looking primarily -- the work that was done on our behalf by Terra Tech was done on the Mallon Davis core.

Q And it's that information, then, that will describe for me the flow into the matrix under the laboratory tests?

A The flow into what we consider being secondary porosity that we -- the matrix is more than just that secondary porosity. It is all the remaining low permeability portion of the reservoir excluding the high capacity main fracture network that we see, for example, on the televiewer logs.

Q And is there a permeability test run on the core or is there some special test that was run that's not otherwise in the record here?

A I believe that all of the pertinent information is in the record but I would have to review my notes to -- to know exactly what all tests were run on the core.

MR. KELLAHIN: Mr. Chairman, with the indulgence of Mr. Douglass, perhaps I could ask this of the witness after we conclude his direct, just as a point of information, and I'll ask Mr. Douglass to define information for me.

It's just a point of clarification of a fact and I don't want to waste time discussing with Mr. Hueni because I can't ask the precise question that I need to ask.

MR. DOUGLASS: Yes, we'll try to get you that date or give you a reference to it.

MR. HUENI: Mr. Kellahin, I

would say that I think we included the entire Terra Tech report as one of the appendices to our March, 1987, report. I believe that's the case.

MR. KELLAHIN: Thank you, Mr. Hueni.

MR. LEMAY: As a point for the record, did you ever clarify the source material that Mr. Douglass went to get so that that can be entered into the record?

MR. DOUGLASS: The Chairman Pro Tem, in acting in your absence, ruled on that.

Thanks for asking. We did work it out.

MR. LEMAY: Okay, fine. Is that all, Mr. Kellahin?

MR. KELLAHIN: Yes, sir.

MR. LEMAY: Are you through, Mr. Carr?

MR. CARR: Yes, I am.

MR. LEMAY: Additional questions of the witness?

Mr. Chavez.

QUESTIONS BY MR CHAVEZ:

Q This is a couple of points of clarification, Mr. Hueni.

The area described as brown on your Exhibit Number Five is the Canada Ojitos Unit Area, not necessarily the entire West Puerto Chiquito Mancos Pool, is that correct?

A Yes, that's my understanding of that.

Q And the volumes that you calculated as far as area are concerned in some of your exhibits, dealt with the area of the Unit, not of the pool, is that correct?

A Yes, that is correct.

Q Okay. One other point, and I saw there was confusion in the questions and all, too, the expansion area is the expansion area for the pressure maintenance project, not for the Unit, is that correct?

A Yes, that's correct, it is the proposed expansion area for the project.

Q On your Exhibit Number Six have you compared the GOR performance of the Gavilan Mancos Pool area to the GOR performance of -- of a pool which may be in the -- nearing depletion by the GOR's?

A No, sir, we have not.

Q On your Exhibit Number Seven -- I'm sorry, I think I've got that wrong.

On Exhibit Number Eight, --

MR. DOUGLASS: Eight?

MR. CHAVEZ: Yes.

Q Did you try to compare individual well performance to the overall pool performance, as shown on Exhibit Number Eight?

A We've looked at -- at the individual wells in order to see if there is relationship, this inverse relationship of rate in the gas/oil ratio, and in fact the -- one of the subsequent exhibits was that type of relationship where we plotted oil rate versus gas/oil ratio for three of the wells, the Loddy Well, the Rucker Lake Well, and the Canada Ojitos 29 Well.

We have looked at -- at the other wells and we've concluded basically the same thing that Mr. Weiss concluded, that there are a large number of them that demonstrate this inverse relationship of higher rates - lower gas/oil ratios. There are several wells that from a statistical standpoint, anyway, they -- they are somewhat not capable of being correlated as to their relationship.

Q As a group how did the wells in the proposed expansion area match the pool performance on this exhibit?

A The only one that I can recall right now is the one that we had on the -- the Canada Ojitos Unit 29 Well, which is on one of the other exhibits where we plotted oil rate versus gas/oil ratio, and that particular well, I believe that was Exhibit Number -- Exhibit Number Ten, the third plot back on that.

Yes, it's on the composite that Mr. Douglass is holding up, and that is the Canada Ojitos Unit 29 Well, and that one very definitely shows this inverse sensitivity, higher rate - lower gas/oil ratio.

I'm not sure on some of the others.

Q On Exhibit Number Thirteen it appears that there is a point at approximately, say, 370 or 360 feet from the top of the Niobrara A where the wells below that level aren't as severely affected by changes in the GOR as the other wells that are graphed. Might that seem to indicate that there's a difference in effect on the producing rate and GOR's by the depth of the well?

A Well, I think that our interpretation is that indeed the wells, some of the wells that are higher gas/oil ratio are indeed also structurally higher wells, but at the same time, when you look at many of the structurally higher wells in that same -- in that same structural position, you don't see these high gas/oil ratios. Basically, you have a large number of red dots underlying the yellow dots.

So you don't see this uniform -- you don't see anything that you could refer to as a uniform formation of a gas cap where you had structurally highest wells being the -- consistently the highest gas/oil ratio wells. You see as low a gas/oil ratio in wells that are structurally high as you see in wells that are structurally low.

Q On your Exhibit Eighteen, which is the reference to a statement about imbibition in a petroleum engineering text, is this imbibition an observed, a measured, or a calculated phenomenon in this reservoir?

A I think it's an observed phenomenon that is the -- it is that phenomenon that results in basically the oil, when you produce at low rates, the imbibition, the capillary forces hold the oil in the higher portions of the rock. The only thing that escapes are the -- is the -- is the gas production. Basically the gas is bled off. I think Mr. Elkins will be talking about that in more detail later, but basically it is an observed -- we -- we use this physical phenomenon to explain the observed phenomenon of why gas/oil ratios are -- are high at low rates and low at high rates, because the imbibition at low rates either pulls the oil back into the low permeability gas-bearing sections or it basically holds that oil in place, doesn't allow it to flow out of the lower permeability sections into the high capacity fracture network.

And so we would -- we would say that

this is an observed phenomenon. It's the same phenomenon that in a much more porous and permeable rock, if you take a core and you put some oil on it, basically that oil will absorb into -- into the rock itself.

Q Is there a certain rate at which you would say imbibition starts taking place and -- or --

A Well --

Q -- above which it ceases?

A Well, it would appear to us, because of the inverse rate sensitivity, that it is in the rate -- it is in the vicinity of the rates at which we're operating the Gavilan Field because it is the explanation for why rates -- why higher oil producing rates go with lower gas/oil ratios and vice versa.

So we would see that imbibition would be one of the factors that would be affecting performance within the rates of -- that were seeing here, but basically we see it as very detrimental to have to shut wells in periodically because of overproduced gas allowables, because the oil that's in that major fracture system just has a chance then to be sucked back in to the low permeability fracture system.

Q But you have no way of quantifying that this is occurring?

A Well, I -- we -- we think that we have quantified it because we think that we have seen that -- in fact all of our calculations have shown that at high producing rates we have low gas/oil ratios while at low producing rates we have high gas/oil ratios. Low producing rates for the Gavilan Field mean 3000 barrels a day. Normal producing rates are going to allow 6000 barrels a day and we see this difference in the gas/oil ratio, so for the field as a whole, we -- we do have a means of quantifying it and that's -- that's kind of what we have attempted to do with talking about our -- our reduction of gas/oil ratio from approximately 4000 down to about 3100 when the normal rates were in effect.

Q Thank you. On Exhibit Twenty-one, which is your graphic representation of Mr. Greer's pressure map, if you were to plot the other Gavilan producing wells to th left on this graph, where would they fall?

A Gavilan wells would be, like you said, would be further to the left and they would cover a distance -- I'm not sure how far to the left they would all fall, but they would begin right on the -- right to the left of this axis that we see and then they would consider -- continue off to the left.

Q Would they be at about the same level as the pressure plots for the wells that you have on there on the east -- west side of the barrier?

A Some of the Gavilan wells that are in the vicinity of Canada Ojitos Unit Wells would be very close to the same pressure as the Canada Ojitos wells.

As you go to the far western portions of Gavilan and we have some isobaric maps that will be presented later, you will see a reduction in pressure on the far western side of Gavilan.

Q What was the rate of withdrawal, say, in barrels per day, of the wells on the east -- west side of this barrier, as you've got them mapped on this graph?

A The barrier on the -- on the west side of the barrier these pressures were taken immediately following the end of the normal rate production period. in other words, these are November, 1987, pressures, so the Gavilan plus the proposed expansion area in total at that point in time was producing only 6000 barrels a day.

Q And the wells that would be on the east side of this barrier, what rate were they producing during that period of time?

A I'm going to have to estimate that they were in the vicinity of 300 barrels of oil per day at that point in time. The March, 1988, rate for the pressure maintenance area was about 243 barrels a day and it was somewhat higher than that in November.

Q Would it be unreasonable to expect a

large pressure drop across a pool where at one area you're having large withdrawals and in another area you're having small withdrawals and injecting gas?

A I -- I think that is -- in my estimation that is a pressure discontinuity. One of the things that I -- that I focussed on when I looked at that graph, is the low rate of pressure change per unit distance on each side of the barrier, and then I see that as a pressure discontinuity at that point.

And prior to about 1986 the pressures on the lefthand side were higher than the pressures on the righthand side, so -- and yet at that point in time -- at that point in time Gavilan was making much more than the pressure in this area was at that point in time, too, so I just -- I just see it as evidence of a pressure discontinuity myself.

Q Thank you.

MR. LEMAY: Thank you, Mr. Chavez.

Additional questions of the witness?

Mr. Lyon.

QUESTIONS BY MR. LYON

Q Vic Lyon, Chief Engineer for the

Division.

Mr. Hueni, on your Exhibit Six what was the source for the (not clearly understood.)

A The data that we have worked with, in accumulating our production information we have received copies of the operators (unclear) reports to the OCD and we have (not clearly understood) and then what we've done on this particular plot is that we have aggregated together all of the production reported in that manner for wells that were producing as of July, 1987, when when the, what we refer to was normal rate test began.

Q Does -- does that also apply to the data before the test began?

A Well, all of the production was, yes, it was -- we have aggregated together all the production information from -- yeah, for any well that was producing as of July, 1987. Basically what we did is we excluded any well that came on production for the first time after July, 1987, and this is just the production profile in sum for all of the wells that are in the Gavilan Mancos area, plus the proposed expansion area, the oil rate and calculated gas/oil ratio for those wells.

Q All right, now to make sure that I'm communicating with you, is the data for 1984 and '85 and '86 the data that was submitted to you by the operators?

A It wasn't submitted to me. It was submitted to the State and we obtained copies from the State files.

Q All right. Those are from the official records?

A Yes, sir.

Q Now how about during the test period beginning in July of '87 and (unclear). Is that from data that is in the official Commission records or is that from data submitted to you by the operators?

A No. Once again it was information submitted to the State and which we made -- which we had copies made of.

Q All right, so that should agree wth our annual report data for 1987.

A It should with the one exception that we've excluded any well from it that began its initial production after July, 1987. With that exception it should agree exactly with those numbers.

Q Now, in order to compile that, you had to add to the Gavilan Pool data the data from the proposed expansion are in the Canada Ojitos Unit, correct?

A That's correct.

Q Have -- have you -- well, -- well, during the lunch hour I plotted the -- the production from the Gavilan Pool as it appears in the annual report and also the gas/oil ratios for the year 1987, and the gas/oil ratios for -- of course the production is -- is less than what you show there because it does not include the -- the expansion area, but the gas/oil ratios are considerably higher for the Gavilan Pool, as is printed in our annual report. So in order for -- for the figure that you show on there, gas/oil ratios that you show, and considering that Gavilan Pool, as depicted in the annual report are higher, then the wells in the expansion area must of necessity be generally lower.

A We know that the gas/oil ratio of wells in the expansion area is lower, I think, than the average Gavilan wells. We, I think you will see later on a presentation by Mr. Roe, who will present a production plot for the Gavilan Mancos Pool itself, and it shows this exact kind of gas/oil ratio reduction on it.

I -- all I can say is I believe our numbers are correct, sir.

Q Well, I don't question your numbers. I just wondered if you had an explanation as to why the wells in the expansion area had so much lower GOR than the wells in the Gavilan.

A Well, I know one of the effects that's been seen in the -- I -- I really can't speak as knowledgeably about the expansion area because we obviously haven't had access to the operator the same way we've had access to the operator in the -- or some of the operators in the Gavilan Mancos Pool, but we've shown on our daily production plots, for example, on the Howard 1-8 and the Ribeyeowids Well that the reduction in -- or the restricted rate has cut back oil production while not necessarily affecting gas production. So we've seen a several-fold increase in gas/oil ratio in the Gavilan area just as a result of the restricted rates. Now why that hasn't fully affected the proposed expansion, I'm not sure that I can answer that. We did show one well, the Canada Ojitos Unit 29, the one that we were just looking at previously, and it did have that same kind of inverse affect on that particular well, but I am not sure if I can knowledgeably speak about why the gas/oil ratios are as low as they are in the remainder of the Canada Ojitos Unit when you know it's essentially the same pressure.

Q Let me -- let me call your attention to another exhibit, and this -- this also applies to several of your other exhibits.

Your Exhibit Nine, where you show the two squares, and one square being the -- what you call the normal rate and the other -- the other square showing the restricted rates, but I notice that the (unclear) with no difference is in your restricted rate area. Do you know how many days that the wells produced in November under the so-called normal rates?

A That -- that's a good point. The -- I think the pressure test began in about the middle of November so it is not a -- it is not a full month of restricted rates, and in fact, it probably shouldn't be colored either way because it is part -- part of that month was in the normal rate period and part of it was in the restricted rate period.

Q Well, I see that it's more consistent with your restricted rate models but actually there was more production under the unrestricted rates than there was under the restricted rates in that month, and I think because of the fact of the preparations for the testing and that sort of thing, not only was -- was November off, but the month of June prior to the beginning of the test was way off, too; and also the month of December was way off, according to the reports (unclear.)

A Well, I have -- I guess I have no indication that that is the case in discussing the matter with the operators that I've had access to.

MR. LYON: That's all I have.

MR. LEMAY: Thank you, Mr. Lyon.

Additional questions of the witness?

MR. BROSTUEN: I have a couple.

MR. LEMAY: Commissioner Brostuen.

QUESTIONS BY MR. BROSTUEN:

Q Mr. Hueni, both you and Mr. Weiss have talked about the shut-in period, testing period, for the wells as far as pressure tests were concerned, and 72 hours was the time that was -- time period that was decided upon by the Engineering Committee or the parties involved.

Was that primarily due to lack of information or prior knowledge of the Proponents' reservoir that you thought that 72 hours would be sufficient or is it tied primarily to economics, that you didn't want to leave the wells shut in longer than 72 hours, or what's the reason for that?

A I'm not sure that I can answer that, Mr. Brostuen. I did not participate in those meetings. I think, you know, you run a test and sometimes you're surprised by what the results show. In this case the results showed at the end of 72 hours following the normal rate test period that the pressure build-up was still significant on several of the wells, at least the wells that we've looked at where we plotted out the pressure build-ups.

I don't know that anybody anticipated that that would be the case and I'm not sure what the basis for the 72-hour test -- selection of a 72-hour test period was.

Q It appears to me that for a number of wells in the -- that there has been very little pressure data acquired at a previous time. I'm not so sure about Gavilan but West Puerto Chiquito plots I've seen. That may be one of the reasons for it.

Getting on to your discussion on the loss of income, the waste of oil, and so on and so forth, related to imbibition, is it possible once that you have essentially depleted your reservoir pressure, or very nearly depleted your reservoir pressure, that gravity drainage would be sufficient to allow the production of the oil that's been re-imbibed within the matrix?

A In our opinion that will not be the case. We're dealing with a low permeability -- with dealing with a low permeability matrix. Some of it would be, perhaps, recovered through gravity drainage but we're dealing with a low permeability matrix.

The principal way to get the oil out of

that low permeability matrix is to have a pressure differential that causes the oil to flow out of -- out of there.

Gravity drainage does not create a large pressure differential. It creates a very small pressure differential. So you need a large pressure differential for that, that flow to occur, and what we're saying is, is that in this lower permeability section we're simply bleeding the gas off instead of -- instead of pushing oil out with that gas.

Q So essentially once that you have bled off that gas and reimbibed the oil within the matrix porosity, that oil is no longer recoverable for all practical purposes.

A It's like a sponge that absorbs water; you hold it up and it's -- it may drip out a little bit but you're not really going to get most of the water out of the sponge.

Q Thank you very much. That's all I have.

MR. HUMPHRIES: I have a few --

MR. LEMAY: Mr. Humphries.

MR. HUMPHRIES: -- and I apologize for part of this because of them are the same point, obviously, that I think you were just talking about.

QUESTIONS BY MR. HUMPHRIES:

Q When you mentioned the pressure differential with the decreased allowances, you mentioned that, as I understood it, your sponge theory would, so to speak, evacuate the major macro-fractures. And then you had the pressure stored in the matrix that released or moved the liquid and the gas to -- to the major or macro-fractures?

A Yes. You need -- you need some sort of substantial pressure differential to cause flow to come out of this low permeability rock into the high capacity fracture system.

Q When you talked about equalization of pressure in between the fractures and the matrix, would you hazard a guess as to time?

A It would take a long time. I think Mr. Elkins may have some information on some other fields about how -- how long some of the -- it takes to get some of these systems equalized. But we're talking in terms of probably more than days. We may be talking in terms of weeks or even months.

Q In your explanation, the two diagrams you showed today and I recall in other hearings, you've described this as a 3-dimensional spider web with the matrix contribution sort of randomly going back and forth through the spider web. Is that --

A Sounds like a fair characterization.

Q In that period of time, in that 3-dimensional spider web, is there any reason, and I clearly understood from your presentation that you don't think that pressure maintenance enhances, in fact you think it inhibits the production of this reservoir, but if you have the spider web in three dimensions going essentially randomly back and forth through any three dimensional section with the matrix being random back and forth through the spider web, sometimes connected to the macro-fissures; sometimes it's connected to micro-fissures, would you not have some opportunity to put pressure behind the sponge, so to speak?

A No, sir, because inside of those little blocks that are encompassed by your spider web, basically the oil has to flow out in all directions out of -- out of those individual blocks. It doesn't flow through them. You don't push through the blocks. You basically have flow out of the blocks. It's from the inside blocks that are contained in that spider web outward into the high capacity fracture system.

So if you try to inject, you aren't going to push through those blocks; you're just going to bypass right around them through the spider web of macro-fractures.

Q Regardless of the fact that the matrix porosity may encounter at multiple --

A In spite of that, because the only thing that would tend to make the -- that would tend to make fluid want to go inside of those blocks, is this imbibition for instance, like a sponge having one too many something be sucked into that, but gas is not going to be sucked in in preference to liquid that's already there.

Q So it's basically one way.

A It's one way.

Q And that's from so to speak virgin pressure until that pressure is depleted?

A That's right, it's -- it's a one-way flow out of those low permeability areas.

Q What's --

A I've got to say, though, it is not completely one way, because if we shut these wells in during -- because they won't produce their allowable, then what happens is that the oil gets pulled in the opposite direction.

So what you do is you pull in the oil through these imbibition forces and that -- that holds -- then that oil is held back in those blocks again.

Q The concept that was presented earlier in that fact that putting dry gas back into the formation, although this wasn't Gavilan Mancos, that theory was kind of interesting to me. Would that -- do you discount that theory completely, that dry gas has any absorption ability whatsoever if the liquids are taken out and reinjected into the formation? In other words, can dry gas not be a sponge as well as this theory of --

A To -- to a limited extent it can, but once again, what you have to consider, and I think the thing that will be very difficult in the case of the Gavilan Mancos Pool is the fact when you put that dry gas in it's not really going to contact very much of the oil. You're basically going to displace the oil out of this high capacity fracture system, and where the oil's going to be left is going to be in the low capacity, the low permeability rock. And so, yes, a dry -- a dry gas through phase equilibrium will absorb some heavier hydrocarbon components. The problem is going to be very simply that this dry gas is not going to be able to contact the majority of the oil that's sitting back in this low permeability area.

Q And that's why you feel that that's permanently lost --

A Yes, that's --

Q -- because regardless of what agent you use to try to inject into the formation, you simply have it trapped into the low permeability (unclear).

A You have no energy; once you bleed off the gas energy, you have no energy to drive the oil out of that low permeability area.

Q That's why you maintain that there's potential or in your opinion there is permanent loss.

A Yes, that's correct.

Q You mentioned in your testimony in Exhibit Twenty-one that it takes about, and I apologize if I don't have this right, but I think this is what you said, that it takes about four days to equalize the pressure in the reservoir and you were concerned, I think, about a reading that was taken immediately after shut-in in one of the injection wells?

A Yes, sir, that's the B-18. The reason I mentioned that is that I believe that some of the data that will be presented later by the opposition includes a fall-off test on a gas injection well, and I think it's fairly clear from that fall-off test that if you were to measure the pressure immediately after that well was shut in it would not reflect the pressure in the vicinity of the reservoir that would -- would -- pressure level that would be reached had you measured that pressure after it had been shut in for three or four days.

Q What I had a hard time understanding about that was if the reservoir equalized, or the pool equalized in four days, why would there be any pressure gradients at all?

A There is -- there is through the -- through the pressure maintenance area a very low pressure gradient, and that is our point, is that there is a pressure gradient indicated by the -- by the map, what we refer to as a rainbow map, that really is a -- is only a pressure discontinuity across the barrier. It's not a pressure gradient either on the west side of the barrier or on the east side of the barrier.

Q But within the pressure maintenance project, I think you were making the point to discount the 1400 pounds because it was on the well that you -- that you felt uncomfortable with that reading being too soon after injection to be valued.

A It's the same thing as if we measured --

Q The B-18 well, yeah, that --

A It's just the opposite case as if we had measured the pressure on a producing well immediately after it was shut in. It would be abnormally low. So we allow it to build up for a period of time.

On an injection well, if we measure the pressure immediately after shut-in, it's abnormally high, so we need to allow it the same opportunity to reflect the true pressure in the reservoir in the vicinity of that well, and had that been done, this B-18 pressure that's shown on the rainbow map in our opinion would have been a pressure much more comparable to the other pressures that are shown on the eastern side of this barrier, this barrier.

Q So if you had no production at all either side of the alleged barrier, would both pools equalize, in your opinion, in a short period of time and you'd have consistent pressures from east to west and north to south?

A I think in the pressure maintenance area that there would be a high degree of equalization after the wells were shut in for not too long a period of time.

In the case of the Gavilan area I think that equalization would probably take a longer period of time, because in the Gavilan area we've been basically taking oil -- well, I just think it would take a longer period of time in Gavilan (unclear).

MR. DOUGLASS: Greg, I think he's also asking you if they'd get to the same level on both sides.

A No, they would not get to the same level on both sides --

MR. HUMPHRIES: No, I wasn't asking that. I'm just --

A -- because the barrier would prevent

that.

Q Do -- you'll have to pardon my ignorance, do slope and depth contribute to pressure?

A We refer instead of pressure many times, we refer to fluid potential, which is the -- some of the effect of pressure plus whatever potential energy it has because of its elevation above some given datum.

By correcting all of our pressures to a common datum, which I think all, pretty much all of the reservoir engineers involved in this case have done, have selected a datum and tried to correct our pressures to that datum, we are taking into account the differences in elevation that exist across the area.

Q You're trying to equalize that so you'll have consistent numbers.

A So we have all of -- so we've taken out the elevation change aspect of the problem and we've just left more of the pressure change.

Q In your conclusion, then, would friction play no part in any difference across the pools?

A No, sir. We don't see it -- we see it as a discontinuity but it is not -- are you speaking of one of the --

Q The pressure gradient.

A We see two separate pools.

Q In either -- in any pool, would friction play a part in a difference in -- if there is a pressure gradient. I mean you can't, obviously, pump by all of the fissures and/or microfractures and macrofractures and matrix without having encountered some friction.

A Right.

Q But you believe that would equalize in a period -- in four days --

A Well --

Q -- regardless of --

A -- it -- it -- friction is -- friction, as we classically think of it, would, like fluid flowing down a pipe, is not really a substantial problem here.

What is the problem here is the -- it's the permeability and the permeability is sort of like a resistance and if you have high permeability, you have very little resistance, so pressures equalize quite rapidly in a pool.

If you have very low permeability or any kind of internal barriers, then it takes a longer period of time for that -- that resistance to be overcome for the pressures to equalize.

Q I have one more question. A question that you were verging on and I can't remember if it was with Mr. Kellahin, or -- I think it was, I believe it was him, that was if -- you had a sort of threshold assumption in your argument, and that threshold assumption that was keyed to the rest of the conclusions you drew had to do with it being a dual porosity reservoir and the fact that there was a very definite barrier, and is that in fact the key building blocks or is that the threshold question from which you build all the --

A I think that --

Q -- rest of your --

A We don't make those two assumptions and then work the problem.

What we have done is worked the problem and found out what physical condition in a reservoir will satisfy the observed behavior in the reservoir.

So it is not in an assumption that that we begin with, it is really a conclusion that we arrive at by looking at the actual behavior of the reservoir, and the two conclusions we have -- have arrived at are first, that there is a pressure barrier there, or just a barrier. It's not a pressure barrier, it's just a barrier between the pressure maintenance area and the remainder of Gavilan and the proposed expansion area. And the second conclusion that we've arrived at is the -- that this system is a dual porosity system. We have investigated many other possible combinations of -- of the physical description of the physmuch emergency school taxes, ad valorem taxes, and --

Q I understand. I just wondered what numbers you applied to them.

A Yes.

Q Would it not be safe to assume, though, that if prices improved any one time through that period of time, or in the future, that you may have inconsistent numbers? You're only dealing with the hypothetical loss, given where we stand today. If --

A Well, we're -- I'm sorry.

Q Q If you saw $30.00 a barrel oil next month, would it in fact conclude, or lead you to believe that there had not been that much economic loss?

A That's right, if oil prices increase dramatically, then it was a wise decision. Well, I say it was a wise decision but on the other --

Q I'm not trying to -- I wasn't trying to lead you.

A -- hand it's not a wise decision because we are incurring, in our opinion, physical waste at the same time we're delaying production.

MR. HUMPHRIES: Thank you.

QUESTIONS BY MR. BROSTUEN:

Q Mr. Hueni, I have one or two more questions.

You discussed secondary recovery or I believe you stated that secondary recovery is not a feasible -- would not be feasible for the Gavilan Pool. Does re-imbibition play a part in that, repressuring? Would that in fact confined the oil to the matrix? Is that a part of the problem that

A Well, if the -- the imbibition keeps the oil in the matrix and there is no spontaneous -- I don't know if there are any -- any substances where -- that spontaneously absorb gas and inject liquid out of them. So basically, this -- lower permeability sections of the reservoir are not going to absorb any injected gas. The gas is going to move down the fractures. Because the fracture volume is relatively small, you're going to have very quick breakthrough of gas. So you are going, then, you're going to experience a very rapid gas breakthrough in our estimation.

If we continue on and produce this field and -- and maximize the pressure drawdown and pull out as much oil as we can out of the low permeability sections of the reservoir, we're going to leave a lot of gas saturation in those areas, and so then if we go in and we try to inject gas and we do manage to move any additional oil, that oil will probably be re-imbibed back into the rock as we move through the reservoir and what we end up with is essentially no recovery as a result of injecting gas.

Q So injection of gas in fact compounds the results of imbibition, or it could?

A That -- that's right. It's certainly not going to offset the -- the adverse affects that imbibition has. The only way to overcome this imbibition, these capillary forces, is to create a high pressure differential and try and pull as much of the oil as we can out of the lower permeability sections of the rock.

Q I think you've answered my question, but the reason I bring it up is it would appear to me that if -- if your theories on imbibition are correct, and apparently someone else is going to testify, too, to the phenomenon of imbibition, is that correct?

A Well, I think I may be the principal person, but we certainly have another person that's considered a worldwide expert -- (not clearly understood).

Q It would appear that if your theories are correct, that by pressuring up the fracture, major fractures, you would increase imbibition of oil into the rock.

A Well, the thing that really happens, it's just by slowing down the rate of oil production that the -- that the rock is given more of a chance to pull -- suck the oil in and to replace whatever gas is in the rock with liquid. So it is -- it's not so much pressuring up as it is not pulling down.

Q I understand what you're saying but by the same token, by re-injecting gas you would pressure up the fractures and condemn the migration of oil out of the matrix, is that correct?

A Well, that's right. If you pressure up on fractures, then you obviously have even lower pressure differential between fractures, between the matrix and the fractures.

Q Thank you very much, Mr. Hueni.

MR. LEMAY: Mr. Humphries.

QUESTIONS BY MR. HUMPHRIES:

Q If you have essentially recovered to the point you feel like no longer can recover liquids and you've got a certain amount of, in tight porosity, liquid and gas, presumably you would have a gas well, would you not?

A Eventually the only thing that will be coming out of the major high capacity fractures is gas.

Q So that gas/oil mixture would ultimately give up its gas under that much lower porosity pressure and maybe no longer take oil with it.

A Well, I think what you do is -- it's kind of just like bleeding something off versus letting it really come out in a hurry. You're bleeding the gas off by producing small without getting additional oil along with that -- that gas recovery. So you bleed off all the gas. In a restricted rate scenario you bleed off all the gas and leave the oil on a low permeability section.

Q And with present technology you see no way to -- no other secondary recovery that would improve that situation. You feel that would continue to be lost, using present technology.

A I think there is another reservoir that is probably a pretty good analog and that's the -- it's a bit different -- it's the Spraberry Trend Area, and they tried both gas injection programs there as well as water injection programs there and the results have not been encouraging.

Q Thank you.

QUESTIONS BY MR. LEMAY:

Q Mr. Hueni, am I to understand that imbibition with -- with gas re-injection, we'll say a pressure maintenance project, we do expect that this gas would occupy the high capacity fractures, that you'd get some, maybe, flashing high GOR's down dip because of that gas injection along the fracture plain?

A You very well could. If the majority of your oil is in the matrix itself as opposed to the fracture system, then injecting gas, particularly under the case -- under the situation where you have very little structural relief, there's no place for that gas to go except through the high capacity fracture system, which is a small portion of your reservoir rock, and therefore, you've got to have basically the gas move towards the producing wells quite quickly.

So it would not be at all surprising to see a rapid breakthrough of injected gas.

Q Maybe your qualifying statement there was in the low area, because it would seem like in the West Puerto Chiquito we have a situation where there has been injection and I wonder if the history of that pressure maintenance project mirrors the conclusions you'd draw from the process of imbibition and suppression of oil in the tight regions.

So you would necessarily -- you wouldn't necessarily expect the gas/oil ratios to increase as rapidly in a case where you'd gone to such a reduced rate.

I think there was one of the other reservoirs that we referred to where they injected gas and they had a -- and in spite of having quite a bit of structural relief, they had a very rapid breakthrough of injected gas down structure, and that was one of the other ones where we indicated that secondary recovery had failed.

I'm not sure if I answered your question.

Q Well, in a sense. I just wondered, here we have a theory to account for the GOR conditions that -- under two different rates of testing -- and that theory, I think, that could be applied to the history of the West Puerto Chiquito Pressure Maintenance Project because that in turn would be a laboratory itself.

But there are some different conditions there than in Gavilan because of the -- the steeper dip.

A The steeper dip and the injection -- the injection of gas has maintained pressure at a higher level than in the Gavilan.

Q But if you're -- you're bypassing the matrix and this gas, I would assume, as I visualize it, would channel around these high capacity fractures and maybe produce some high GOR's in some of the lower structural wells within that maintenance project.

A Well, I'm not so sure if you produce it at a very low rate that it will channel down the fractures as much as it will spread out laterally across the field and stay in the fracture system at the top of the -- top of the reservoir and then move down more uniformly.

Q Well, then I'm trying to visualize these high capacity fractures. They must occupy a pretty good percentage of the volume of the rock so that you get a sweep within the high capacity fracture system itself compared compared to the lower.

We're talking about a relative thing, aren't we?

A We talking about a relative thing in the Gavilan Mancos area. We believe that fracture volume is only 10 percent of the volume. We have no real idea what it is in Canada Ojitos Unit, although we know, I think, that the opposition believes it's 100 percent.

I think Mr. Weiss' indication for the Gavilan Mancos area in the study that he did, indicated that over 90 percent of the volume was in the -- in what we refer to as the matrix as well and only 4 percent in the fracture system.

Now whether those conditions are really

different conditions between the pressure maintenance area and the Gavilan Mancos Pool, and I don't feel prepared to say, particularly on the Canada Ojitos Pressure Maintenance side.

Q I guess I have a hard time visualizing it's a gradational differential in size of the fractures, where you -- what you're calling primary and secondary or high capacity or low capacity. There doesn't seem to be a cutoff on a diameter fracture that would put it in one category of the other, is there?

A There's not a -- there's not a firm cutoff. I think you could -- you know, we don't have rock where you look at one piece of rock and it's 1000 millidarcies, and you look at another piece of rock and it's one millidarcy, and there's a distinct cutoff in between there.

But I think you would naturally suspect if you injected gas into that same rock, if you put it in parallel and you injected gas into both of them, that the gas would preferentially down to the 1000 millidarcy rock and probably not --

Q With that kind of differential.

A Yeah.

Q Just a couple of other things we need to touch on.

You believe the barrier is there, naturally, because you're testifying to that, and associating a lot of this expansion area with Gavilan, and yet on your Exhibit Fifteen, you show two wells that are very close together with quite a bit different producing characteristics, one well being in Gavilan and the other in the proposed expansion area.

I can see why both sides want to get this expansion area into their camp because it's a pretty nice area 17 (unclear) barrels a month.

I just have a hard time visualizing it being so similar to Gavilan when we have two wells right next to each other that show such markedly different characteristics.

A This Exhibit -- now you're referring to Exhibit Number Fifteen, is that right?

Q Yes, I am.

A Well, keep in mind that these two wells do not exhibit markedly different characteristics.

The Howard 1-8 Well, which is shown as 20 barrels a day, that was the one where we looked at the daily producing capability of that well under the normal rate period and that well made 300 barrels a day. It's not a poor well.

Q Yeah.

A It's a poor well only because of the

gas/oil ratio restriction on it.

Q I'm referring to the GOR's in both those wells. They both look like significantly producing wells but the GOR's vary so tremendously in just a short distance, along with what Mr. Lyon was referring to as low GORs in the expansion area. I have a hard time in my own mind saying, well, this is -- this is -- these similarities are very close to Gavilan. They are pressurewise but they seem to be different in other characteristics.

A Well, I think the only real differences we see are in this producing gas/oil ratio and -- and it's very difficult to understand why the 29 Well and the Howard Federal 1-8 would have -- would have this different a GOR.

We have had data presented to us by Mr. Greer before that indicated these wells are in excellent communication, just almost instantaneous communication, and yet,of course, there is a little bit different producing mechanism, one's a gas (unclear) well and the other is rod pump.

But I don't know if that really accounts for it. There are variations in gas/oil ratio between wells both across this boundary, as well as within the Gavilan Mancos Pool, significant variations in gas/oil ratio.

But one thing that we have seen is that

each time we go to a restricted rate, the gas/oil ratio tends to jump up on these wells.

Q More so in the Gavilan proper than in the expansion area?

A I think the data that we've presented in Figures 14 and 15 indicate that the expansion area has a lower gas/oil ratio than the -- than the Gavilan area.

Q In that regard it's more of a producing question and I don't know if you want to answer it, but if you can, I'd appreciate it, if you want to maximize oil recovery, like you do, under periods of lower allowables, why not produce that well full blast for five days rather than ten days and get the benefit of capacity flow, then shut it in so that your ratios will be, I'd assume, as low as they would be producing ten days rather than five days, rather than just restrict the flow on those wells?

A Yes, in fact, if I could refer you back to Exhibit Number -- unfortunately I don't do a good job of numbering exhibits -- Exhibit Number Eleven.

Exhibit Number Eleven is the Howard 1-8 Well where, if you look at the period of time beginning with the restricted rate, which took effect in mid-November, this period of time, the operator subsequently chose to produce their gas allowable for short bursts at as high a rate as the wells would make.

In this case over a short period of time they could only get the wells up to 100 barrels a day; perhaps it was because of operational instabilities, I'm not completely sure on that.

Gas production during that same period of time was about the same level of gas production that they had prior to the restricted rates. So the gas/oil ratio was higher.

But these are periods where they attempted to produce the well at maximum rate and they were unable to do that.

At the end of this period they went through a test to see if they would produce on a continual basis, 30 -- as many as just 30 days a month, or 31 days a month, if they could choke back the well and make a constant volume of gas, if they could achieve a lower gas/oil ratio by doing that. We don't have the numbers here but I think if these numbers were calculated, in fact, I know if these numbers were calculated, they would show a lower gas/oil -- they would show a higher gas/oil ratio and a still -- and a much lower oil rate. This is a continual oil production in through here. This is the gas production that goes with it.

So once again we came to the conclusion that if you have to produce at very low rates on a continual basis, you have these imbibition effects. It's better to try and produce for short bursts of time and take out the gas at whatever rate you did before, even though you don't get as -- you don't get the oil back to that same rate.

Q And you don't know how long it would take the continuous production to get that well back to rates that would be optimum, which means lower GOR and higher oil producing rates?

A Well, I -- I think you -- you know, we don't have any technical study, but I think if you looked, when normal rates were -- the normal rate test period was introduced in early July, I think you'll notice that there is, for both wells, a period of time where the rates actually come up on those wells.

In other words, the first several days on the Howard 1-8, the rate's down in the range of 100 to 200 barrels a day, and it's only after several days that they're able to get this production rate up to this level.

Similarly, for the Ribeyeowids Well, initially following the restricted rate period, several days, it takes several days for -- to be able to get back up to this 80 to 90 barrel a day rate, and what happens is that when you can only produce the well for 80 -- for maybe 7 or 8 days a month, you never get back to a capacity type production.

Q So those graphs show it takes about 7 or 8 days to get it back to capacity and then you tend to produce that well at capacity until your allowable and then you would even shut it down if it's capable of higher producing rates than even a higher allowable?

A I'm not sure if I understand that.

Q Oh, I'm trying to visualize an optimum producing rate.

A Yeah.

Q You say it's going to take some time to get back up there to optimum producing.

Q You're not restricting at all, based on -- on even the higher allowables, are you? You're flowing it at whatever it will make --

A That's right.

Q -- and then shutting it in after you make the allowable even at the higher producing rates?

A At the higher producing rate it is not affected by allowable. It -- it hadn't -- it was not affected by the allowable.

Q There's no restriction on even gas/oil ratio?

A There was no restriction on this well during this period, so it was not shut in during this period. So -- but it did take a period of time and we aren't prepared to say exactly what that period of time is, but it did take a period of time to get the well back up to its capacity type production.

And then what happens in here is that the well has to be shut in fairly frequently and you just turn it on for a few days and you're not able to get back to the capacity on the oil. The gas stays up high.

Q Mr. Weiss had a -- refer to page 20 of his exhibit, if I could. He's talking about the Gavilan Dome recovery efficiency in barrels per psi pressure drop. He has a couple of wells in there that basically show increased pressure that I guess I'm looking for explanations for, it's finding pressure support somewhere. One explanation, I assume, is that the barrier is not there and that somehow there's gas injection pressure reaching those wells through some channel way.

The other may be pressure support from outside the current confines of the -- of the field boundaries.

Do you have any explanation for that pressure support that's shown there?

A Well, I think -- I think you need to keep in mind when you look individual wells' pressures that the first thing you have to keep in mind is the degree to which the pressure was actually built up at the time the test was taken. So if you take a pressure that's based on an arbitrary 72-hour point after the well is shut in, that may or may not be built up. The data we presented as Exhibits One and Two indicated that after the normal rate testing period the well was still building at a fairly high rate of pressure increase after 72 hours.

Okay, now, so that's one thing to consider.

The second thing to consider is -- and we think that's a very -- we believe that is a very important, important factor to consider. It's, we think, very significant.

The other thing, though, that we -- we also note, when you look at individual wells, as you change their relative allowables and you -- you change the allowable on one well versus the other well, you change the drainage patterns around those wells. So even within a pool you're going to have oil moving around in different areas basically in response to -- to the pressures.

So we see that there can also be oil influx from within the Gavilan Mancos pressure expansion -- proposed expansion area. We can see oil influx in the areas where you have large, large amounts of withdrawal.

So once again, when you look at data

such as presented on Table 4, you look at it on an individual well basis. You don't have to conclude that influx comes from outside the reservoir, it can be, one, because pressures aren't fully built up and, two, it can be a readjustment of oil within the pool itself that occurs; however, we do have exhibits that will be shown later that indicate there is an isobaric trend where you do have a trend of higher pressures in the Gavilan Mancos proposed expansion area that this trend runs somewhat to the northwest.

MR. LEMAY: Thank you.

Any additional questions of the witness or redirect?

MR. DOUGLASS: We do not have any redirect.

MR. LEMAY: Fine. The witness may be excused and let's take about a ten minute -- a fifteen minute break.

(Thereupon a recess was taken.)

MR. LEMAY: The hearing will come to order.

Mr. Pearce?

MR. PEARCE: Mr. Chairman, at this time the Proponents call Mr. Lincoln Elkins to the witness stand.

Although Mr. Elkins' face is not familiar to the Commission, we assume his name is since a number of parties have cited Mr. Elkins' writings on fractured reservoirs in the papers that they've presented to this commission, and we thought we should bring Mr. Elkins to talk about fractured reservoirs.

LINCOLN F. ELKINS,

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. PEARCE:

Q Mr. Elkins, would you please state your full name and occupation?

A My name is Lincoln F. Elkins, E-L-K-I-N-S. I am a consulting petroleum engineer.

Q Mr. Elkins, are you aware that Bill Weiss and John Lee have relied upon your study of fractured reservoirs to support their conclusions about the proper engineering management of the Gavilan Mancos Oil Pool?

A Yes, particularly in Mr. Weiss' preliminary report he quoted two papers. He has one of them on the Spraberry, a reference in his revised booklet, and he has one quotation from me directly. I think when he was quoting anisotropic, degrees of anisotropy, or permeability variations in different distances he was at least in part quoting the material from a second paper, which he did not reference.

Dr. Lee has included two of my papers on the Spraberry as part of his exhibit in the April, 1987, hearing and has two or three quotations in his testimony, quotations quoting statements of mine from one or more papers.

Q All right, Mr. Elkins, you have been in the room for the proceeding part of this hearing the last couple of days?

A Yes, sir, I have.

Q What other materials have you specifically reviewed in preparation to testify?

A Well, I was invited to take a look at the material that is the subject of this hearing towards the latter part of May, and particularly I had an opportunity to review the preliminary book prepared by Mr. Weiss and the testimony, I think, at two different hearings by Dr. Lee.

I also asked to at least have a summary

review of the material that the Bergeson Group have prepared to the hearing so that I could get some background of what the questions were.

Q And was that the -- I'm sorry.

A The real question posed to me was after reviewing that did I believe that the Spraberry was a good analog to use in interpreting performance of the Gavilan Pool and --

Q And what is your opinion on that question, sir?

A Well, I think it is a very excellent analog of demonstrating some of the physical features of performance of tight fractured reservoirs.

Q All right.

A I do not think it is identical so that you can say we did in the Spraberry, exactly the same thing in barrels, pounds, everything that's going to take place in the Gavilan, but I do think it is a very important analog.

Q All right, sir. Before we get to the substance of that, in order to apprise the Commission of the basis and reliability of the conclusions you are going to express, could you summarize your educational background for us, please?

A I graduated from Colorado School of

Mines with a degree in petroleum engineering in 1940.

I attended Texas University at Austin in 1940/41 and completed all of the course work but not a thesis towards the Master's degree.

Q All right, sir, would you summarize your employment history for us, please?

A I was employed from 1941 to 1945 by Stanoline Oil and Gas Company, which is now Amoco.

My original assignment was to develop a reservoir engineering and research program for the company and towards the last couple years of my employment I was more equally involved in analysis of reservoir projects and really these were what now would be called enhanced oil recovery projects.

In 1945 I moved to Conoco where my title was Production Engineer but my function was really reservoir engineering and to a large degree I studied a number of on-going gas injection pressure maintenance projects that Conoco has.

In 1947 my boss moved to Sohio Petroleum Company and a few more months after that, why, I tagged along and I stayed there for 35 years.

Q All right, sir, that sounds like we're approaching 45 years of practical petroleum engineering experience.

A Well, it's -- it's -- yes, and this is hands on, applied reservoir engineering experience. My entire career has really been spent in applied reservoir engineering.

Q All right, sir. Mr. Elkins, are you an Honorary Member of the Society of Petroleum Engineers?

A Yes. My peers have been very kind to me. Honorary membership is the highest honor granted by SPE and I'm one of 32 out of some 50,000 members of the Society.

Q And are you a member of the National Academy of Engineering?

A Yes. Again, as I stated, my peers have been very kind to me.

In 1863, as chartered by Congress, the National Academy of Sciences was created with the function of advising the government on scientific questions, and as time has gone on, why, it was very apparent that scientists were not capable of covering the entire scope of science and technology, so something like 25 years ago the National Academy of Engineering, a sister organization, was established under the same original charter, and a few years ago I was elected to the Academy and there are currently about 12,500 -- correction, 1250 members of the Academy out of more than a million engineers of all categories in the country, and there are less than 30 petroleum engineers in the Academy.

Q All right, Mr. Elkins, both Bill Weiss and John Lee have cited papers which you have written.

Approximately how many papers have you written and had published in your career?

A Well, Perry, it's about 20 and they are all related to actual performance of reservoirs and in every case to the degree possible I was really trying to interpret and explain the performance of the reservoir in it and just sort of reciting in summary the performance of the field.

Q Some of those papers have related to fractured reservoirs, is that correct?

A Yes, sir, I published four papers on the Spraberry, two of which were quoted by Mr. Weiss and Dr. Lee; two additional papers on the Spraberry that neither one of them did quote and which I think, based on additional performance provide additional insights into the reservoir performance of a fractured reservoir.

I published a paper on the West Edmond Hunton Lime Unit, which is a fractured carbonate reservoir that's located just outside of Oklahoma City.

Both of these are very low permeability, fractured reservoirs, not as low permeability total, at least, as the formation under consideration here.

Q All right, sir, you've indicated that you have studied and written papers on the Spraberry and the West Edmond Hunton Lime. Are there other fractured reservoirs which you've studied or worked with during your career?

A Yes, sir. Sohio Petroleum Company was part owners of the Madden Unit in the Wind River Basin in Wyoming and this is very tight, fractured sandstones; it produces gas, but there the permeabilities are just as low as the permeabilities in the cores or the matrix of the reservoir under consideration here. I have for the last five years been a member of the Technical Advisory Committee to the Department of Energy in their experimental field research project on the Mesaverde tight gas sands with wells drilled near Rifle, Colorado.

I have had some peripheral involvement in the same aspect with the Department of Energy studies in Devonian Shale gas production back in West Virginia. I proposed a gas tracer test.

I was consulted by Los Alamos National Laboratory and the other contractor on this both before and after conducting tests.

So I've had -- I've had some exposure to the detail, although Sohio had no interest at all in any of the wells.

Q All right, sir. I think it may be a little easier if we shift the mike more so you can face the Commissioners, and at this time, Mr. Chairman, I would ask recognition of Mr. Elkins as an expert in the field of petroleum engineering as it specifically relates to fractured reservoirs.

MR. LEMAY: He is so qualified.

Q Mr. Elkins, Bill Weiss and John Lee have referred to your paper and have stated certain conclusions based in part on that work.

After reviewing the materials mentioned above and applying your expertise, do you agree with the conclusions stated by the gentlemen?

A Well, each of them stated a number of conclusions. Some of them I agree with; some others I do not.

Q All right, I think we may be able to shortcut this if I may display what I would like to identify as Proponents Exhibit Thirty and I would ask you, Mr. Elkins, to please go through the information displayed on this exhibit for the Commission.

A The first one is a statement that the bulk of the Gavilan oil is in the matrix.

The second one is that injecting gas into a fractured reservoir system will not recover oil from the matrix.

And the third one is that in Gavilan, of course, oil will be lost if the highest possible pressure differential is not maintained between the matrix and the fractures.

MR. PEARCE: I apologize, Mr. Chairman, I have induced some confusion.

We have changed the order of witnesses. Mr. Elkins' exhibits are at the back of the notebook, are the last set, and begin with page showing this exhibit. That is Exhibit Thirty, as we are numbering those now.

So we will proceed through those in order now and then perhaps we'll just move the whole set forward later.

Q All right. Mr. Elkins, before we begin specifically discussing each of these conclusions which you have reached, I want to ask you if you were present in the room when Mr. Weiss testified regarding the relationship of oil production to pressure drop during the various testing periods?

A Yes, sir, I was.

Q Do you have some comment with regard to that analysis?

A Well, the principal statements, I don't remember the numbers exactly, but during the period of low rate production, I think that he had something like 540 barrels per pound drop.

MR. PEARCE: I've approached the witness. I'm showing him page 20 of Mr. Weiss' exhibit.

A Yes, for the period from November 19th to February 23rd, he calculated an average of 543 barrels per psi, and I'm quite sure that this is an arithmetic average of numbers derived for about eight different wells, some much higher, some lower, for the period from June 30th to 11 -- November 19th, I assume this is 1987, the period of normal production rate. That average was only 98 barrels per psi.

Q Based upon your experience in working with tight fractured reservoirs, are you surprised by those numbers?

A No, sir, I think that after a period of low rate production the pressures in many of these tighter reservoirs tend to build up faster than they do after much higher rates so that the pressure drops that he observed n these individual wells may not be truly representative of the pressure changes that took place in the reservoir.

They are reflective of the pressures that were observed in the fracture system, except that it's not all one or all the other.

The reason for this concern is that in the West Edmond Field, which is one of them that I will be discussing today, this field was unitized in 1947, and this was a period just following World War II when rates were high. Much of the gas was being vented.

One of the benefits of unitization would be able to shut in wells that were wasting gas and they could sell it.

There was a 4000-acre area of this field that was totally shut-in for a period of two years while the operators were first deciding whether to build a gasoline plant and then actually to order the material and construct the plant and the gas line in order to market the gas.

In that period the pressures which normally then had been measured with 48-hour shut-in pressure, they increased by 300 to 400 pounds over that two year period and largely over the entire area , so that it's reflective that in these tight reservoirs pressure measured in the well, even with an adequate, seemingly adequate, period of pressure build-up was not truly reflective of the pressures in the entire porous system that contains oil and gas.

Q All right, sir. Let's look now at your first conclusion, and I would ask you to briefly describe the engineering analysis you performed to reach that conclusion.

A Well, let's begin it by looking at what I found had been used by Dr. Lee in his model study of performance of his gravity drainage model, and that, I think, comes from his exhibits on the hearing date of April 3rd, 1987. Or it could be a different one; I've got only an individual sheet here.

But he concluded that the hydrocarbon porosity was .27 percent; the total porosity was .3 of a percent. In his text he has described the matrix permeability under overburden load or in situ stress conditions and water saturation of being so low that it just -- it just was -- should not even be considered to be practical.

Based on my experience in the Spraberry, or let's say building on my experience in the Spraberry and in West Edmond, I thought that this at least should require additional detailed study.

One of the factors that Dr. Lee quoted me on and used as part of the basis for his interpretation interference test was the application of the exponential integral mathematical relation being applied to tight, fractured reservoirs, and I did that in the Spraberry as one of the exceedingly large interference tests, and I agree that it is applicable under many conditions and I have examined both what he did in his analysis, which was partly correct and what he did not do, which I think he should have done, and which I did in my analysis of the Spraberry back in 1951.

He has in this exhibit book two or three graphs where it shows the pressure drawdown measured in an interference test. It's in the pressure maintenance area where, as I remember, the -- the entire area had been shut-in for quite some time in order to let the pressures equalize.

The Well T-11 was then put on production at about 480 barrels a day and fluid levels were measured in the L-11, the A-14, and the A-23 Wells, which are half a mile to something more than a mile away, and the fluid levels, which were accurately measured, as I've been told, began to drop within the first day or two and over the period of 29 days the reductions in fluid level changed -- converted to -- drops in pressure were of the order of 10 to 20 pounds.

I believe, although I cannot be for sure from the very limited information in his exhibit, that then he analyzed a second period when the L-1 Well was put on production at about 1000 barrels a day with the first one continuing, and I think he analyzed the differences between an extrapolation of that earlier decline curve I considered going into the first part.

The values that I obtained for the transmissibility of Kh, or darcy feet, were at least of the same order of magnitude as those derived by Dr. Lee. They're really for two different parts of the tests and for a different producing well, and he has indicated, I'm sure I could find the exact words, but this is adequate to characterize the reservoir, that if one of the fractures that is deriveable from the test is the darcy feet of flow capacity. If you knew the thickness if 40 feet in this model, which I think is probably reasonable for the C Zone, then that would yield a permeability measurement.

The other fracture, which is deriveable from this matching of the idealized theoretical relationship to the actual pressure drawdown history, is if you knew the thickness accurately, you can derive the product of compressibility and porosity.

If you do not know the thickness accurately, you could derive the product of thickness times compressibility and porosity.

In his model he states that the rock compressibility is $10 \times 10_6$ and this is volume per volume per psi.

The oil compressibility is about the same based on either the bottom hole sample analysis that he used or at least one that has come from their group.

The water compressibility by laboratory tests with be on the order of 3.

So that's -- and he said that the oil saturation is 90 percent; the water saturation, 10 percent.

If you combine all of those values it adds up to a total of 19.3 x 10_6. This is the total of the rock, oil and water compressibility, and if I use the 40 feet of thickness which seems pretty reasonable, the calculated porosity, as reflected by the actual performance of these three observation wells in that interference test, averages 3-1/4 percent. That's more than 10 times higher than the pore volume that he has assigned to the fractures in which he concludes that that's the only place that recoverable oil exists, so that in this interference test, analyzed by both Dr. Lee and I in exactly the same manner, it is a direct indication that the pressures sensed in that 29-day test reflected the entire porosity of the matrix and the fractures not just the fluids that were in the fractures alone.

Now in his analysis he also has taken the core analysis, permeability, for unfractured little pieces, which average about .02 millidarcies, and has corrected them to in situ conditions under the mile and a half of rock that's piled on top of them and the high water saturation, and he has a number for that as an effective oil permeability that is a decimal point followed by zero, by 5 zeros, then 646. (.00000646)

Now I'm acquainted with the paper that he referred to. I have additional data on tests that were conducted in this DOE project on cores that are in the same range of .01, .02 millidarcies, and those cores under the same compression with 50 to 60 percent water saturation, have the same order of magnitude permeability.

Q If I may interrupt just a moment, Mr. Elkins, let's say that value again, a decimal point followed by how many zeros?

A By 5 zeros and then 646.

Q All right, sir. Thank you.

A Another way of expressing that, it is .06 microdarcies, because we engineers are bothered with so many zeros, the same as everybody else.

Now, I've made a second analysis to determine whether this apparently exceedingly low permeability should mean just total rejection of the rock matrix, or whether it needs to be considered.

I have assumed for a basis of calculation that major fractures are 2 feet apart and I've calculated that with the pressure being dropped down in two fractures on both sides of the block it takes less than an hour before that pressure wave reaches the center of the block and that in the 29-day test period, which I was analyzing, and he analyzed a similar one, the pressure in the center of that block should have dropped by about 99 percent as much as it does in the -- in the fractures themselves.

The inference to me is that this is -- no, let me back up.

I made my own analysis based primarily on laboratory tests on cores for Mobil but also reviewing these other extensive tests on the Mesaverde sand performed for DOE. I think that a better value for the rock compressibility is 30 x 10_6 rather than the 10 x 10_6 he used.

I assumed that there was probably 30 or 40 percent oil saturation in the matrix, and then applied the correct values for the oil and water.

That yields a total rock and fluid compressibility of, let's see, I used -- I used 35.8. When I used that with the 40 feet of thickness that I assumed, I get a total porosity of 1.8 percent. This is very much in line with the core porosities of, oh, 2 to 2-1/2 percent when they are reduced due to the application of current --

for the in situ stress conditions.

So that not only does -- well, these -- these two numbers are very much together now and it leads me to the conclusion that the fracture system is adequately extensive, connecting small enough matrix blocks that even though the permeability is apparently so exceedingly low, actually fluids are drained out of the matrix into the fractures and then to the wells within the period, in this case, a matter of days, or one month.

The next point that I would like to make, and this is an analogy with the Spraberry, and this comes from performance under waterflooding, which we're going to discuss a little bit later, but whereby from the performance of the reservoir, and I'm talking about a 3-/12 mile square area for performance of the reservoir, we have by actual reservoir performance an indication that the fracture porosity in that part of the field in the Spraberry is about .01 percent. Now it's 30 times smaller than what Dr. Lee assumed for his gravity drainage model.

The transmissibility, or this darcy feet, of flow capacity derived from my interference test there, were about .9 versus about .35 for this part of the pressure maintenance area, and it's also within 31 feet.

If we assume the ideal behavior of perfect parallel fractures, then the porosity varies, or let's say the flow capacity varies as the cube of the fracture opening. If I make those corrections, and use the Kh values derived from this interference test, it would raise the fracture porosity by analogy with the Spraberry reservoir performance up to .015 percent, and that's only 1/20th of what Dr. Lee assumed for his gravity drainage model. I have no idea what his basis was for making that assumption but it just doesn't tie with my own analysis of this interference test and my analogy with large scale performance of the Spraberry Field.

Q All right, sir, can we move to the discussion of your second conclusion at this point?

A Yes, the -- the second question has to do with how tight fractured reservoirs behave, in this case with gas injected into them.

One of the concerns of all reservoir engineers is that the gas will just whistle down these cracks and not displace any oil.

I would like to talk first about performance of the Spraberry during waterflooding because I was very deeply involved in it and I know all of the background and I made some analyses, and then I would like then to continue into actual reservoir performance of the tight West Edmond Field in which both pilot gas injection tests were conducted and in which a large scale waterflood test was conducted.

Q All right. Mr. Elkins, as part of the discussion earlier in the day, we've had some talk about and some questions relating to imbibition. In your work with the Spraberry reservoir have you been exposed to that phenomenon?

A Yes, sir. There are really two parts to it but let's look first at what happens with injected fluids.

Q And I have displayed and would like to introduce at this time what we're marking as Proponents Exhibit Number Thirty-one.

A In the early 1950's it became very apparent that the performance of the Spraberry was going to be -- the natural production performance of the Spraberry was going to be somewhat disappointing, and that's an understatement.

Most engineers, including me, just concluded it almost offhand that waterflooding wouldn't work because the water would channel rapidly down these fractures.

Atlantic research engineers were given the assignment to come up with something. Atlantic owns big lands out here, you find a way to make some money out of it. And two of them, examining the behavior of the reservoir, performed tests that -- now this is a very enlarged example, but they took a little, probably, that may be 1-1/2 inch by 1-1/2 inch core plug, saturated it with oil, and put it in a beaker of water and within a matter of a few hours, in this case the rock as a strong blotter, or it had a strong affinity to absorb water, and it actually absorbed water in ovr all of those spaces and expelled oil out with flow in the opposite direction.

Q And what we're looking at, Mr. Elkins, on what we've marked as Exhibit Thirty-one, is an actual copy of a photograph which shows that oil droplets form on that core plug, is that correct?

A Yes, sir, it's a photograph from a paper that they presented, so it's -- it's a photograph of a reproduction in their publication, the American Petroleum Institute.

Another part of their test, this demonstrates the physical principal, but they conducted another test in which to be a little more quantitative in the evaluation of the process. They cut horizontal slabs of the Spraberry rock from cores and these are three pictures all of the same test.

The sample is 1.5 by 2.7 inches, then by .25 inch thick, and they sealed all of the edges except one edge. thin part of it, the .25 inch part. They filled it with oil that had a chemical put in it which is opaque to x-rays, so that when the x-rays go through it, it's black. The x-rays don't go through it, so it shows up black. This is sort of like the x-rays and see your bones but not your flesh because there's a difference in the absorption.

The top, Panel A, was the initial conditions. It shows it was completely full of oil.

The second panel, labeled B, was a picture taken after 21 hours, and Panel C, a picture taken after 47 hours, and I think it's apparent, even across the room that water had moved in and expelled much of the oil and I think in 47 hours that's really about a half an inch that it penetrated. They made calculations of what would happen under the reservoir and predicted extremely good waterflood performance by this process.

Atlantic carried out a limited pilot test that resulted -- they didn't have a lease big enough to complete a full 5-spot so they had three injectors with one producer. They injected water in these three wells and it reduced gas/oil ratios in the trend, oh, probably for a mile in both directions from that well. It stabilized production but it's like 15 barrels a day and nobody got excited in 1953 for a 15-barrel a day waterflood at 7000 feet. clearly understood.)

Later Humble, which is Exxon, conducted

a test in the Pembrook Area, the southern part of the field, and, you know, it was an area not fully developed. They had to drill some additional wells in which to complete a 5-spot. They injected water at much higher rates into the four outside injection wells and produced the center well, and I, as I remember that center well, which was a brand new well, came in making about 80 barrels a day and with waterflood it increased it up to 250 barrels a day and -- and performed excellently, and this was what triggered attempts at large scale waterflooding. Sohio was the ringleader, or was the point man on trying to promote these large units.

We put together the Spraberry Unit, which covers about 100 square miles and we started with a 9-square mile Texas-size pilot waterflood to determine how it would perform and I think it's time now to put --

MR. PEARCE: Excuse me, if I may, Mr. Chairman, I'm labeling the last exhibit with the three photographs as Proponents Number Thirty-Two.

I'm now going to display what we're going to mark as Proponents Exhibit Number Thirty-three to this proceeding.

A This is the -- a daily graph of production, oil production, water production, and water injection into about a 3-1/2 square mile portion of that pilot waterflood.

When we started injecting water it didn't perform at all like the Humble test. The water came through with no oil bank being created and it created somewhat concern.

In analyzing the performance, I was convinced that we were injecting water in this area, 16,000 barrels a day, far faster than the water was capable of imbibing water just on its own. I finally convinced my boss that we ought to just quit injection for awhile and see what would happen and let it soak and come into balance.

Q All right, sir, and we're addressing the top portion of this exhibit, the first part, which shows water injection at about 16,000 barrels a day.

A Yes, this is in September of 1961.

Q All right, sir, and you've indicated that after you did a little talking you persuaded management to stop water injection, is that correct?

A Yes, and you can see on the graph there in early October that the water injection in this part was reduced to zero.

Q All right, sir, and looking at the bottom portion of this exhibit, what was the resulting effect on oil production?

A Well, it surprised even me; I never suspected anything like that. In five days this area increased in oil production from 350 barrels a day to 1050 barrels a day.

Some wells that had been making 100 percent water went to 100 barrels of oil a day and with low water cuts.

Q All right, sir, looking at this display, there appear to be three other periods in which water was once again injected into the reservoir at amounts exceeding 20,000 barrels a day.

A Yes, sir.

Q Is that correct?

A Yes, sir, that is correct.

Q What was the effect of each of those periods of beginning water injection?

A Well, our objective, of course, was to pump the reservoir back up and then let the capillary forces hold the water in the rock and let the expansion of fluids expel the oil and as we were producing, particularly after March of '62, why, the reservoir pressure was declining and the rates were declining that was as much as the wells could make.

I think the most dramatic one to examine the question we're considering is in September of --

October of 1962, when we suddenly increased water injection from zero to 14,000 barrels a day, and within at least 10 days the oil production from that are dropped from about 900 barrels a day to about 80 barrels a day and actually the bulk of that 80 was coming out of the lower Spraberry in wells that were -- in some producing wells that were -- that the two zones were commingled.

What this means in terms of behavior of fracture is that we just flushed all of the oil out of the fractures in that very short timed; that everyone of the four periods that are shown here when we -- after we'd injected at high rates and then stopped injecting, this area came back with more oil production rate than it had just before we'd been injecting.

It's actually based on one of these periods where with the combination of pressure reduction and the changes in fluid that I have the evidence that the fracture pore volume was about 25 barrels per acre, certainly no more than 50 barrels an acre, and the zone under examination is 31 feet, so that's where I get the fracture pore volume based on actual performance being the order of .01 percent, 1/10,000th of the total volume of rock.

Q All right, sir. On this exhibit we have discussed the results of injecting of water and therefore raising the pressure in a fractured reservoir. I would ask you at this time if you have some evidence about the effects of gas injection in a fractured reservoir?

A Yes, I have. My next exhibit describes performance of a pilot gas injection test in the West Edmond Hunton Lime Unit, which I've mentioned is just outside of Oklahoma City.

This is a tight fractured carbonate reservoir.

MR. PEARCE: Okay. Mr. Chairman, I'm marking this as Proponents Exhibit Number 34.

A And one of the purpose of unitizing the West Edmond Field was to increase recovery by gas injection. There was great differences of opinion among many of the operators as to whether gas injection in that kind of a reservoir would work or whether it would not.

One requirement of the unitization agreement which was blessed by the Oklahoma Corporation Commission was the conduct of the pilot gas injection test before large scale gas injection pressure maintenance could be instituted.

One of the tests was run along the eastern edge, this is a pretty flat monoclinal reservoir, in an area where gas/oil ratios were fairly high. It had been shut in because our total gas producing capability was more than the gas plant's capacity.

This test was conducted with gas injection into two wells labeled 614 and 632 with triangles around them; most of it into the north well, 614. The production of gas and oil was measured daily by individual wells for all of the surrounding wells.

We started it in March of 1948. That group of wells together were producing about 150 barrels of oil a day and, oh, 4-1/2 to 5-million cubic feet of gas a day. That was more than the injection capacity of the compressor, so we -- we cut the gas production down to match the volume of gas that we could be injecting. We balanced, just like Mr. Weiss indicated ought to be done in Gavilan.

Q What was the effect of that?

A Well, the effect is dramatic; you can see it. Within a day or two the oil production of that group of wells dropped from 150 barrels a day down to about 15 barrels a day. The gas/oil ratio increased from, probably, 15 or 20,000 up to about 200,000 cubic feet per day.

We carried that injection on until about the middle of July with being somewhat imbalanced or even over-injected. Now this means that at least locally in that area the pressure was being maintained.

We put helium in as the tracer in the gas injected and in about 10 days the -- started just before the 1st of May, it showed up in one of the wells, 623, within about a week; in two other wells within about ten days; and then six wells within two months.

Calculations based on this time of helium tracer moving through the reservoir indicated that the gas was flowing through about 10 percent of the total pore space.

Then in the middle of July, 1948, we -- we had observed enough to see how it was performing with balanced gas injection pressure maintenance, and the only thing that was done was to to push the red stop button on a compressor, quit injecting gas, and almost to the day, oil production started to increase, going from about 15 barrels a day for the entire group of wells up to about 75. By the end of September the gas/oil ratio had dropped from something more than 200,000 down to about 50,000 cubic feet per barrel.

In this area, obviously the injected gas had essentially swept all of the oil out of the fractures and kept it swept out, not -- nothing new was coming in out of the matrix, or at least there was a very moderate volume.

Q All right, sir. One of the questions

that came up this morning, Mr. Elkins, was whether or not solution gas drive itself could keep the oil moving through the fractures and keep those fractures swept relatively clean of oil accumulation. Do you have information relating to that question?

A Yes, sir, we can look at the next exhibit, which is waterflood performance, a part of the West Edmond Field, which is only a few miles west of where this pilot gas injection project took place.

MR. PEARCE: I'm going to mark this as Exhibit Number 35, Mr. Chairman.

A In late 1949 we started water injection first into two down structure edge wells of the field as a temporary salt water disposal in order to alleviate a problem that we had.

This was expanded into injecting wells along the down structure edge of the field in about a four mile wide strip. This graph shows the water injection in the upper part that increased from about 5000 barrels a day up to nearly 8000 barrels a day in that period.

The other part of the graph shows the oil production for this four mile strip across the field, which was declining and at least from 1951 to 1953 had established a very well defined decline.

In that period of water injection we

moved the water front as much as a mile and a half across the field, not all of it that much but from a quarter of a mile to a mile and a half across the field, and we created no water or oil bank that stimulated production from a single well in this entire strip.

Q What did that indicate to you, the fact that during this water injection moving that water front you did not create an oil bank?

A Well, there just wasn't any oil there in the fractures that the gas drive from solution gas drive performance of this had kept the fractures swept quite clean of oil.

Q All right, sir, looking at what we've marked as Exhibit Number Thirty-five, it appears that in about mid-1953 water injection was stopped, is that correct?

A Yes, sir, it was.

Q And what's the result on oil production of stopping that injection?

A Well, we stopped injecting water and within actually weeks oil production began to increase and by early 1955 it reached a peak of 1900 barrels and through a 5-year period it averaged about 900 barrels. This was not from an oil bank created at the front where the water came. This came from wells that were completely watered out during the period of water injection.

As a matter of fact, in a pressure survey we found an oil gradient in one of the well former water injection wells and put a pumping unit on it. That well had had a million barrels of water injected into it and we produced 131,000 barrels of oil out of it by the time that I wrote the paper.

Q All right, Mr. Elkins, let's turn now to your third conclusion, if you would, and if you'll please refresh our recollection by restating that conclusion for us.

A Well, let's see, the final conclusion is that oil will be lost if highest possible pressure differential is not maintained between the matrix and fractures.

Q All right, sir, I'm going to now display what I'm going to mark as Exhibit Thirty-six and I'd ask you to briefly discuss this exhibit for the Commission.

A This exhibit is a graph of some laboratory tests conducted by Botset and Muskat with Gulf Research, published in 1939, which graph also was reproduced in my first Spraberry paper.

Q All right, sir.

A And as a little background, this is part of what I had studied in my beginning job to develop a reservoir engineering research program so that I became very familiar with everything that as published.

When the Spraberry -- our first Spraberry wells were completed in July and August of 1951, by December or by the end of the year, we had some pressure data. I had a little bit of gas/oil ratio data from some earlier wells in another part of the Spraberry Field.

Sohio had approved budget to drill 200 more Spraberry wells in 1952.

With all of this as the background, the cores, the fractures, everything else, I had recognized what the performance was going to be; that after a certain amount of oil was recovered, then this capillary end effect would become effective and we were going to get very low recoveries.

In an hour and a half long 3-way telephone conference call, including our Manager of Production, our Manager of Exploration, and the Vice President, I shut down that drilling program. We drilled two wells in 1952.

We went to the Railroad Commission, got permission to conduct an extensive interference test, did a little bit of laboratory work. That paper, the first one, and this is the one that has been referred mostly, is basically my testimony before the Railroad Commission, where we got it changed from 40-acre spacing to 80 + 80, or really 160-acre spacing.

Now, let's look at how these capillary effects behave with solution gas drive production of oil. This actually was a test of a small core, probably an inch and a half in diameter, and couple of inches high. It's good rock. It's 480 millidarcies and about 22 percent porosity.

They were investigating what happens when a core is brought rapidly from the bottom of a well to the surface where solution gas drive may expel some of th oil so that what is measured in the core is not representative of what was in the bottom of the hole.

They found that when they produced this at a very low rate, each black dot is a separate test on the same core. The lowest one was production at about a half of a psi drop in pressure per minute. Then there's two more at one and up to about one and a half, and in each of those the recovery was -- the oil left afterwards was about 90 percent saturation. There was no connate water (not understood).

When they increased the rate of pressure decline from 1-1/2 pounds up to 2 pounds, that oil recovery was increased from 10 percent of pore space up to 20, and then when they went clear up to about 4 -- about 5 or 600 pounds per minute, this means a 2-minute test, they just blew it down in 2 minutes. They got down -- they got recovery clear up to about 32 percent of the gas.

Q All right. Mr. Elkins, that's 480 millidarcy, 22 percent porosity rock, and you've indicated that that -- the result of that test by Botset and Muskat was that if you reduced the pressure faster, more oil comes out of the rock.

A That's right, but the other key point is that at very low rates, that you get a certain recovery essentially independent of the rate.

Now what this amounts to is that in the beginning, and this would really at any rate, but in the beginning you -- you -- gas bubbles are formed in each of the cores. You can only create the gas bubbles by removing some of the oil from each well in volume and until these gas bubbles have grown to a high enough saturation that they connect, then there isn't any capillary effect. That much oil is expelled and beyond that, if you maintain it at a very low rate, why, you bleed all the gas off and leave the rest of the oil behind.

If you reduce it at an exceedingly high rate, then you get much higher recovery because the capillary retention forces are relatively less compared to the friction drag of gas moving --

Q All right, sir. In the Gavilan Pool we're not fortunate enough to have 480 millidarcy rock with

22 percent porosity.

A Right. No, sir.

Q All right. Have you information related more to the type of rock we're dealing with in the Gavilan?

A As part of my studied of the Spraberry before we went to the Railroad Commission, we conducted tests on the Spraberry core and the data are displayed on this and it's taken from my paper, also.

This was a 1 millidarcy core so we've dropped down in permeability by a factor of nearly 500 from the Gulf test.

Q All right, sir.

MR. PEARCE: For identification, Mr. Chairman, I'm marking this Proponents Exhibit Number Thirty-seven.

A In the first test, and this was -- this core was filled, it had some water saturation in it, and then it was filled with oil from a bottom hole sample from the Spraberry, and then produced at a controlled rate of pressure decline.

The one that's labeled Test No. 2 was reduced at 100 pounds a day. That means it took three weeks to bleed that low a core down, and we measured the oil that was left in the core and it indicated an oil recovery of about 7 percent.

Q The next test, labeled Test No. 1, was blown down at a rate of 200 pounds a minute. Actually the valve was stuck open and it just blew, and the oil recovery was 52 percent.

So have two tests on a 1 millidarcy core that sort of straddled the ends of the tight performance of the multiple point test conducted by Botset and Muskat.

Now, in reality, then, we have a third test but the third test covers tens of square miles. This was the Spraberry performance by natural production by itself.

The Spraberry permeabilities of cores, there were few that were more than a millidarcy; there were many of them, I would say maybe a third, or something, that were in tenths of millidarcies, and then there were others that were down in the hundredths of millidarcies; doesn't fall quite as low as in Gavilan, but it's getting towards it.

Those permeabilities reduced by the overburden pressure and connate water saturation would get it down into, probably, the .01 millidarcy.

So went another 100-fold reduction in permeability, and in my paper was an analysis based on the early gas/oil ratio trends which indicated that the recovery was going to be 7 or 8 percent. We didn't quite make that. It was smaller than that but we did produce oil out of it at moderate gas/oil ratios after the reservoir pressure had been reduced below the bubble point pressure or saturation pressure.

So I'm totally convinced that the -- that the -- that this is a significant scientific explanation that covers permeability ranges of 10,000 or more different -- that with solution gas drive which is different than injecting gas, but with solution gas drive, when you start to produce out of the matrix itself, the oil is -- is removed and gas bubbles are formed and they are formed in essentially every pore, and until there is enough oil removed that these gas bubble connect, then it's essentially production at solution gas/oil ratio, past that point which is the order of magnitude of 10 percent gas saturation. Then it's very dependent on the rate of pressure decline, the permeability and other factors, and the recovery can be as -- 7 to 10 percent, or it can be 30 percent.

Q All right, Mr. Elkins, earlier in the day the Chairman asked Mr. Hueni some questions about how we could have as much gas injected into the West Puerto Chiquito as we have had and not have gas breakthrough; if we expect rapid gas breakthrough and, for instance, you show very rapid breakthrough in the West Edmond. Can you address that question for us?

A To a degree. I' m a little bit at a disadvantage in that I have never seen any detailed well performance in the pressure maintenance area. I only know a little about the total composite performance.

The dips of the structure in that area are at least much higher than they are in the Gavilan Pool itself and I'm pretty sure without checking that they're also much higher than they were in West Edmond.

There is the possibility, at least, in the pressure maintenance area that there -- that within the fracture system itself there had been effective gravity segregation and I would really expect that, and these are fractures that are open thousands of an inch or more and the oil ought to drain to the bottom and the gas to the top.

But that doesn't mean that it's going to have any impact on how you get the oil out of the matrix into the fractures and some of the data that I have seen in a comparison of different pools in the same formation here today, at least the comparisons as presented showed that the pressure maintenance area wasn't really doing as well in barrels per acre as many of the other fields; that rate of pressure decline in the pool has been significantly re- duced by the re-injection of gas. In fact it's taken 25 years to get it from -- down to 1400 pounds, or so, where the others have been reduced very rapidly.

So I think that while he may have been able to produce wells with not too high gas/oil ratios that are successively down structure in that pressure maintenance area, it doesn't mean that he has increased the expulsion of oil out of the matrix into the fractures by his injection of gas.

Q All right, sir, let's review very briefly for the Commission, would you state again what conclusions you have reached?

A My first conclusion is that the bulk of the Gavilan oil is in the matrix, not in the fractures. I would think by my studies and my analogy with Spraberry, that it might be 10 percent or maybe 20 percent here, where it was only 1 or 2 percent in the Spraberry. Spraberry is a ore porous rock.

And the second conclusion is that injecting gas into a fractured system will not recover oil from the matrix, and I think that my demonstrating to you with the pilot gas injection test in West Edmond, which was actually gas and showed that it just shut off the oil coming out of the matrix, and then when we quick injected gas, the oil started out of the matrix again.

I think that also is supported by the waterflooding tests in West Ed-- or I mean in Spraberry, where we injected at very high rates and in a matter of days we had drawn out all of the wells, they were now producing nearly 100 percent water.

The third conclusion is that oil will be lost if highest possible pressure differential is not maintained between the matrix and the fracture, and I think that my primary basis for that conclusion is the last material that we have discussed, which stems, to my understanding, at least, stemmed first from the laboratory tests conducted 50 years ago by Gulf, the laboratory tests that I sponsored or directed on the Spraberry, that would have been 1952, so that's 36 years ago, and the performance of the Spraberry itself

I think here is one of the very big differences between my analysis and that, at least, that I interpreted from the testimony by Dr. Lee. He has talked about that the capillary pressure in this rock is so very much higher that it will essentially eliminate the possibility of any oil being produced from the matrix. The exhibit, I mean the paper that he presented showed capillary pressure, capillary end effects when gas was being injected into some cores, but this was at a time when the gas saturation was 30 and 40 percent. Behavior is radically different in this beginning performance with solution gas drive, where at least the tests all indicate that you get up to 810 (sic) gas saturation before the gas/oil ratios start up, and I'm convinced in my own mind that this is a phenomenon that is relatively independent of permeability over extremely wide ranges of permeability.

Q All right.

MR. PEARCE: Mr. Chairman, at this time I would like to introduce what I would -- what I want marked as Proponents Exhibit Thirty-eight, which is a set of papers shown at the back of the notebook. These are copies of the papers which Mr. Elkins has -- has been discussing, and at this time I would move the admission of Proponents' Exhibits Thirty through Thirty-eight.

MR. LEMAY: Without objection Exhibits Thirty through Thirty-eight will be admitted as evidence.

MR. PEARCE: Thank you. Pass the witness, Mr. Chairman.

MR. LEMAY: Thank you, Mr. Pearce.

Mr. Douglass, do you have any questions of the witness?

MR. DOUGLASS: Do not.

MR. LEMAY: Let's see, going over -- Mr. Kellahin --

MR. KELLAHIN: Yes, sir, thank

you.

MR. LEMAY: -- any questions?

CROSS EXAMINATION

BY MR. KELLAHIN:

Q Mr. Elkins?

A Yes, sir.

Q When we look at Exhibit Number Thirty-seven, this display shows us the core properties for the Spraberry core. These are ambient condition core properties?

A Yes, sir.

Q And we have a porosity value of 8.15 percent --

A That's correct.

Q -- and a permeability of 1.1 millidarcies.

A Yes, sir, that's correct.

Q When you made the calculations or analyzed the core and calculate to determine the effective oil permeability for the Spraberry, what were the ranges of effective oil permeability for that pool?

A Well, this is one of the better cores of the Spraberry. In our routine core analysis it was rare to have permeabilities over a millidarcy, and I'm speaking totally from memory now, I don't have any of the detailed data. I would think that probably, maybe half of the cores in this 31-foot zone had permeabilities that -- these ambient permeabilities that were tenths of millidarcies. I mean the whole range from 1/10th to 7 or 8 or 9/10ths and that the other half had permeabilities that were -- were down in the hundredths of millidarcies.

They probably weren't all expressed because many laboratories, if it's less than 1/10th, why, that's all they reported, not any lower value, back in that era.

Q In the Spraberry Pool what was the determination by the engineers for that pool of what the effective oil permeability number was?

A I don't believe that there was any number determined like that. This is 1951; this aspect of looking at reduction of permeability under in situ stress conditions and tight rocks didn't -- it was in the middle to late sixties before anything was published on that and, of course, clear up into the eighties with more refined analyses. So we had no tests.

Q Were the field observations of these cores when they're taken out of the formation put on the surface, could you make visual observations that the oil would bleed on the surface of the core sample?

A I cannot tell you for sure. I saw all the cores but they -- but none of them when they were first taken out of the formation (unclear) coming out of the well, which is the time that you would observe a bleeding core, if there were any.

Q That would indicate that a visual observation by which you have taken a rather high pressure differential, taken the core at pressure in the formation, put it at ambient conditions, we have a pressure differential, and if that pressure differential is enough, we ought to see some oil stains on the surface of the core.

A I just don't know what was there. This was 1951.

Q Okay.

A And I saw many of these cores but long after the cores had been removed from the well.

Q Is my assumption correct that if we have oil in the matrix in a core exhibiting this type of properties, that when you take it to the surface you're going to see an oil stain on the core?

A I think you see oil stains on lots of cores over a very wide range of permeability.

Q When you look at the Gavilan Mancos core properties --

A Yes.

Q I believe you gave us some ambient condition core properties. The core porosity was 1.9 percent?

A I think I stated range but many of them, I assume, have that -- well, they're less than 2 percent to -- up to 2-1/2 percent or more for individual plug samples, but a good average, around 2 percent.

Q And the absolute permeability, then, is .041 millidarcies at ambient conditions?

A Well, I quoted .018 from what Dr. Lee had used, but -- but that's not a bad number from just a casual examination without tabulated data.

Q Those core properties from the Gavilan Mancos represent very low permeabilities for that reservoir, do they not?

A Yes, sir, they do.

Q Of any of the reservoirs that you've had practical experience, do you know of any others, other than Gavilan Mancos that has permeabilities of values that low?

A I think parts of West Edmond have to be that low and I told you one part of it here that is 4000 acres was shut in for two years and the pressures built up 3 or 400 pounds.

There's another very pertinent part of

it, the estimates made at the time their field was unitized were that there were 600--million barrels of oil in place and the solution ratio was 1000, so the gas in place was -- would be 600-billion. We have produced more than a trillion out of that reservoir and material balance calculations made progressively through that period showed increasing oil in place and historically this has been one of the clues that there's water drive in the reservoir, except that we can look and see that the water, natural waster influx was drying up, so what we were seeing was the fluids in gas and liquid coming out of tight parts of that reservoir where it took years to really see the expansion effects of all of it.

So that's at least down into the range that are reflected here. In fact, I think in my paper on that I made a calculation of the effective permeability of this area where the pressure built up and Dr. (unclear), whose involved with gas storage, says, "That's a good caprock."

Q Have you studied the Gavilan operational pressures in the Gavilan to determine what have been historic pressure differentials?

A No, sir, I have not. I have made -- I have only a cursory review of the details of the Gavilan performance and the pressure maintenance area performance.

Q Can you approximate for us what ranges of pressure differentials would be necessary in order to have the matrix flow -- the oil flow out of the matrix into the fractures?

A I've made a second calculation. I gave you one that -- in that interference test, which was above the saturation pressure, so it would all be just liquid oil and liquid water and rock, and if fractures were two feet apart that the pressure drop in the center was about 99 percent of the pressure drop on the fractured (not clearly understood.) at the end of this 29-day test.

I have made another calculation for -- which really would be the Gavilan area, which has produced 5-1/2-million barrels, mostly within four years. I mean it's not all because it started earlier than that, but the big bulk of it.

Q Has the matrix been contributing all along to the production in the Gavilan?

A Well, I believe it has but let me tell you what my calculation is.

I assumed again that there were fracture spacings -- fractures were every two feet, at least your major fractures, and that -- so if I took a square mile, why, I've got 2640 of these blocks in there.

Q And I -- excuse me, to describe the

process, in identifying these blocks you've placed the fractures two feet apart?

A Only for a hypothetical calculation. My analysis of the Spraberry performance, which I've published, indicated that ideally they're about 19 inches.

Q Are there any other factors or parameters that go into a hypothetical?

A Yes. Well, I assume the permeability to be this 0.5065 that Dr. Lee mentioned in his testimony and with which I agree.

Q You and Dr. Lee agree on that?

A Well, after seeing it I checked the data that I have on all these tests from -- for the Department of Energy and they're in the same ballpark all right, I have no disagreement with that level.

Then I have assumed that in this period oil production, while the bubbles are growing before where you produce oil out of essentially solution gas/oil ratio, that the effective oil permeability got de-capped (sic) by the presence of these bubbles.

And I have calculated on that basis that the pressure drop from the center of the blocks out to the fractures only has to be .4 of 1 psi to have -- to match the actual production that has taken place.

Now I don't know how far apart the

fractures are. I've seen the Mobil borehole televiewer which has some places where apparently some visible fractures closer than that, but it's -- at least by my analogy with the Spraberry, why, it's something that is within reason and actually, at least in the pressure maintenance area, Kh factors, the darcy feet of permeability, are higher than in the Spraberry, so you can have closer fracture spacing.

Q If the core sample in the Gavilan Mancos represents core porosity of 1.9 percent and the absolute permeability on that core at ambient conditions was .041 millidarcies, if we take that core to the surface and field observations show us that there is no oil stain on the core, never bleeds, we never see any oil on the surface of the core, would that indicate to you that the matrix is not going to contribute?

A Not necessarily, because I -- I would expect that the oil saturation in the Gavilan, in this area, is fairly moderate. It may be not more than 20 to 30 to 40 percent, as contrasted with, I think, higher oil saturations in at least half of the Spraberry interval, which is also pretty tight but not this tight.

I think removing the core from the bottom of the hole and to blow out some of the oil and it's not necessary that the oil would still show as an economic certainty. There is oil in the cores. It's been analyzed.

Q What we're seeking here is how to get that oil out of the --

A I know it, and my recommendation to you is to maintain the maximum pressure differential between the rock and the -- and the fractures.

Q Thank you.

MR. LEMAY: Thank you, Mr. Kellahin.

Mr. Carr.

CROSS EXAMINATION

BY MR. CARR:

Q Mr. Elkins, when this proceeding began the Chairman indicated that some of the attorneys were incompetent. In this area he's definitely talking about me, and I have some questions. Some of these may be very fundamental and I hope you'll bear with me.

If I look at your conclusions, the first of the conclusions is the bulk of the Gavilan oil is in the matrix. Now, just to start me off, when you say matrix, what do you mean? Does this include, as did Mr. Hueni's description, microfractures, or is that something other than that microfracture?

A I really think that it would include,

well, intergranular porosity. There are very tiny holes in there. I think it also would include microfractures which go short distances. It really is a contrast between, let's say, visible open fractures and the much finer, but it's a spectrum; it's not -- it's not all black and it's not all white.

Q So it's a question of degree --

A Yes, that's correct.

Q -- if you get from the fracture system into the matrix.

A Yes, sir, that's correct.

Q The next conclusion you had was injecting gas into a fractured system will not recover oil from the matrix.

If I understand that, the gas that you're injecting is not going to recover oil from the matrix, what you need is a pressure differential between the matrix and the fractures.

A That's right. I know of no mechanism or a steady gas injection into a fractured reservoir that's going to find a way for that gas to get inside that block of rock and blow the oil out of it.

Q And what is going to is sweeping through the fracture system?

A Going through the fractures, why, if

there's oil there it will sweep it out, or it will sweep out the oil that is coming out by a solution gas drive as long as the pressure is continuing to decline.

Q And I guess you also know that we are the opponents and we don't necessarily subscribe to a dual porosity system, but you can assume that for any other questions that I'm going to ask you, as they probably make no sense unless we do.

If the gas is moving through the fracture system and there is a differential, a pressure differential, between the matrix and those systems, even with the gas moving through, do you have some oil migrating out of the matrix in that kind of a situation?

A I think yes, sir, as long as there is a differential, but I think that if you'll look back at the field tests that we performed in West Edmond where we did our best to balance gas injection and gas production, the oil -- oil rate went down very, very low and the gas/oil ratio went very, very high, and so, sure, we were sweeping some oil out. As soon as we quit gas injection, the oil started to come out faster out of the matrix.

Q In the West Edmond was there any, in your opinion, any effect or gravity drainage in that pool?

A I don't think that there is gravity drainage in the sense of an oil moving to the west down structure field and gas being accumulated at the top. I think there are many aspects of what was going on, but at the time that the field was unitized we had high gas/oil ratios in areas that were down structure from the area of the still highest oil production and much lower gas/oil ratios.

Q So it was not as to gravity drainage, so it wouldn't be comparable to what we see in the West Canada Ojitos, certainly and the Canada Ojitos --

A Well, I think there are many other things that have to be considered.

The production rate from the pressure maintenance area has been exceedingly low compared to many other fields, not only in that same formation but any place else, and so just say that -- you have to examine all factors that are involved before you can zero in and say, well, yes, here is the factor that is controlling.

Q You know, when I was talking to you a minute ago about the gas moving through the fracture --

A Yes.

Q -- and there being a pressure differential and there might be, I think you stated, you know, some oil coming out of the matrix in that situation, is there rule of thumb or anything you could share with us as to how much of a pressure differential is required or is this again sort of a gradational sort of thing?

A Well, it depends on the rock and this rock, after you --

Q When you say "this rock", you mean Spraberry?

A Well, no, I'm talking about the one in Gavilan.

Q Okay.

A I'm talking about here.

Q Okay.

A There's two regimes of performance that have to be considered.

The first one, there is the early stage when pressure is being reduced and gas bubbles are being formed, and the gas bubbles can only be formed if you remove oil to create space for them. Until those bubbles, or the number and the size of them, grow to the point that they coalesce or connect, then there isn't any such thing as a capillary force that is holding the oil back. It's only after there is a high enough gas saturation that the gas can flow out. Then at the very low rates you could produce essentially all -- all of the rest of the gas and leave all of the rest of the oil behind except that in -- by that time, why, you would have gotten 6 or 7 or 8 or 9 percent of the oil in place recovered.

Q In this particular reservoir in the Gavilan, do you have any idea how much of a pressure differential this requires?

A Well, I've tried t explain to you that there's two regimes; that the first period --

Q And I understand that, but is there -- is there a number or is it just dependent upon sufficient change in the pressure so the gas can work into the matrix?

A The first part is while the bubble are growing and before they have coalesced, any pressure differential will expel oil and in here, at least within the range of any of the laboratory experiments, that period, that's independent of the rate of production. It's only after you have removed enough oil that the gas becomes a continuous phase, that then the pressure differential affects the efficiency of recovery of oil.

Q And at that time you say the pressure differential?

A Yes, sir.

Q Is that some thing you quantify by percent or a number or just what is there --

A No, sir, because what this is is when the -- at that time after you have a continuous gas phase, there is a certain capillary pressure and I don't know what it is --

Q And it depends on the quality of the rock, is that what it does?

A Yes, sir, but you -- in order to -- in order to recover oil at that time the pressure differential on the gas has to be higher than this capillary pressure or end effect and if you operate with a lower pressure differential than that, you can bleed all of the gas out and leave the oil behind.

In that Spraberry core test No. 1, no, No. 2, the one where we got the low recovery, we -- we got essentially just gas out after we had dropped the pressure to 1000 pounds, so we got that oil out in the early stages and then after 1000 pounds, as was in my paper, why, it was all gas.

Q If I could direct your attention to Exhibit Number 36, this exhibit, I believe, shows actually a pressure range within which you expect this to work, is that correct?

A No, sir, this is the pressure range, rate of pressure decline, for that core sample which was 480 millidarcies.

Q All right, and there is an area at the top that says "recovery not rate sensitive", then a second block below that, "recovery increased by higher pressure differential at higher rate."

That is the range within which what we're talking about works, isn't that correct?

A Well, in this lower range, which is the period -- at any rate of pressure drop, until these bubbles are formed and connected, you're going to get a certain amount of oil out.

If you're in this lower range down here, and you double it, it doesn't do you any good because the capillary forces are strong enough that they hold of the oil back and let you bleed all the oil out.

If you are operating in a very high range -- rate of pressure decline, or pressure difference from in the matrix out to the fracture, it's not very rate sensitive, (not clearly understood) 600 psi per minute, almost a tenfold rate, there's not much difference in the recovery.

If you happen to be in this range, where this core test, where they increased it from 1-1/2 pounds a minute up to 2 pounds a minute, it made a lot of difference. It doubled the recovery, and I would -- I have no way of knowing for sure, but I would not be a bit surprised having seen the data on -- in the Gavilan's test at normal rates and at reduced rates, where the gas/oil ratio is changed enough in the opposite direction, that parts of the reservoir are not down in this part of the curve.

But for me to tell you what the pressure drop is, I have no way of knowing.

Q And you pointed down in the lower part of the curve when you talked about Gavilan production being down in that range, is what you said or not in that range? I just didn't hear you.

A All right. I think that because the field tests had demonstrated that the curtailed or restricted rates of production resulted in increased gas/oil ratio, and then subsequently testing at the normal rates of production reduced the gas/oil ratio, that within the principal (not clearly understood) parts of the Gavilan reservoir may be in this range of the balancing between friction drag, pressure drop, and capillary forces, but for me to tell you it's so many pounds or fraction of a pound, I have no way of knowing.

Q Well, if it varied from well to well, I'd have a very good system.

A Certainly, it very well might.

Q Now, if I understood your testimony, it appears to me that you indicated that the size of the pore space in the fracture has a direct bearing on the rate at which the oil will move out of the matrix, is that correct?

A Well, in an extreme, yes. If the entire reservoir had no fractures in it, you couldn't get any oil out of it.

Q And so --

A But it's -- you get down do small fractures, I mean blocks that are measured in inches to feet, I think it is in that -- in different block sizes, then these rates would be different where the capillary end effect becomes important.

But the key feature is that independent of all of that, as long as you have the fracture, I mean reasonable size fracture blocks, not -- not no fractures in all the reservoir, that you're going to recover this minimum amount of oil which I think may be in the range of 8 to 10 percent or a little more by solution gas drive before there is a continuity of and a gas flow.

Q And does the size of the pore space in the Mancos matrix itself affect the flow rate out of the matrix?

A Smaller pores create lower permeability and higher capillary pressure end effects.

Q Let's just assume, and I'm going to try and get this questions to you and see if I can get it to you so you can understand, let's assume that you have -- you have no matrix. All your porosity is in the fracture system. That you have two wells and my question is, will the oil in place vary as the cube root of the ratio of the

Kh?

A For perfectly idealized fractures, which would be like two Johanson gauge blocks (sic) that they use to measure millionths of an inch, they're perfectly parallel, perfectly open, then the flow capacity of that varies as the cube of the opening so that the reverse would be true, that if you determined the flow capacity, you could back calculate the opening, and I have done that as an idealized model for the Spraberry so that I might have a feel of what's going on but I know that the Spraberry fractures don't consist of these perfect, uniform fractures but man never can understand anything; he makes simplified assumptions to serve as guidance to judgment.

Q Now, did -- I believe you previously testified you've run some calculations on the Gavilan; that you've looked at some 1985 interference tests that have been reviewed by Dr. Lee.

A It was 1965 --

Q 1965, I'm sorry.

A It was 1965.

Q And the question I have is just to be sure we understood your testimony, did you say that you got the same Kh or basically the same Kh as Dr. Lee?

A They were -- they were of the same magnitude. I'm quite sure that he analyzed a period when both the P-11, L-11 Wells were producing, and he analyzed the difference between the extrapolated decline in fluid level from the P-11 into the observation of the L-11.

The part of the test I analyzed was when only the P-11 Well was producing and fluid levels were being observed in three observation wells.

Q And would the A-14 be one of those?

A Yes, the A-14 was one; the A-23, and, let's see, I guess it's the L-11 was an observation well during that first period.

Q Now, when we talk about imbibition, how long does that take to (not clearly understood), I mean, is this something that when we (not clearly understood) back into the formation, does it move sort of in the same time frame in the same fashion as the oil coming of it?

A I can't really tell you, but one of the things that was observed in West Edmond was that, and this was fairly early in the operation, was that they didn't find any fluid levels in a well. They dropped a pressure gauge in there and it was gas all the way to the bottom, so that even though the well had been producing oil and good to high rates, as soon as they'd shut it in, why, the oil went back some place.

Q Does this get worse with time?

A I wouldn't be a bit surprised but what it does. I can't quantify that for you but --

Q In the Gavilan, have you calculated what percent of the oil is in the fracture system as opposed to the amount, what percent in the matrix?

A No, sir. I have made, by analogy, an order of magnitude calculation. I told you that in the Spraberry, based on the cyclic water play, that we had direct field evidence that the fractured pore volume was on the order of .01 percent, and that in Gavilan the Kh factors in this one interference test averaged about 3.5 darcy feet; in the Spraberry .9 darcy feet. It's 31 feet versus, I've assumed 40. If that's the case, then with this cube ratio, it would increase the fracture porosity in Gavilan to .015 percent.

Q We've talked about the Kh figure that you got in your calculation --

A Yes.

Q -- on the Gavilan.

A Yes.

Q Were we correct in understanding that the h is a porosity of 1.8 percent per 40 feet, is that a correct figure?

A That is. Let me double check. Yes, 1.8 percent is what I back calculated out of the other part of the match of the exponential integral relation to the observed pressure drawdown.

Q And that was assuming 40 feet?

A It was assuming 40 feet and it was assuming a rock compressibility of 30 x 10_6.

Q 30 or 38?

A 30. The total compressibility of the oil and 40 percent -- I mean of the rock; 40 percent oil at 10 percent, or at 10 x 10_6, 60 percent water, and 3 x 10_6 adds up to 35.8.

MR. CARR: That's all, Mr. Chairman. Thank you very much.

MR. LEMAY: Thank you, Mr. Carr.

Additional questions of the witness?

Yes, sir, Mr. Lyon.

QUESTIONS BY MR. LYON:

Q Mr. Elkins, I've heard of the West Edmond Hunton Lime Unit about as long as I've known you, since you were one of the first people I met when I went with Conoco. And I've known about the Spraberry Pool since about the first time I came to New Mexico in 1953.

You have related to us your very interesting experience in attempting to find a process to improve the recovery of oil in those reservoirs and you've told us about the waterflood, the water injection, well, I guess first the gas injection, which didn't work, water injection, that didn't work. What was your ultimate strategy in recovering oil from those two areas?

A It was basically just continuing primary solution gas drive operation to the ultimate economic limit.

Q And in pursuing that strategy, did you have any complications with the regulatory agencies?

A There aren't any that I know of while I was actively involved with each of them.

Q Now, in -- in both of those units you had something which we don't have here in this case and that's unit. Would you have suspected that there might be some violations of correlative rights had you not had units in those reservoirs?

A Well, I'm not a lawyer to interpret all of the law regarding correlative rights. The general understanding that I have is that the regulations provide each operator or lease owner the opportunity to compete for the production that he has available from his lands.

Q But would you agree with me that if you've got a large enough area and enough wells, a common ownership, that you can play with the wells and shut in the wells that are inefficient and produce the wells that are more efficient and thereby recover the greatest amount of recoverable oil?

A Yes, sir, that is a possibility. In effect that's what we really did in both the West Edmond Hunton Lime Unit and the Spraberry (unclear). On the Spraberry, part of it was put under extended waterflood; probably half of it was not.

Q But the -- if I -- if I understand correctly what you've told me, what you actually applied was your best management practice for the wells and the properties involved.

A Yes sir.

Q Thank you.

MR. LEMAY: Thank you, Mr. Lyon.

QUESTIONS BY MR. LEMAY:

Q That Spraberry waterflood that Humble was doing, was that referred to as the huff and puff?

A No, it was not. It was the Driver Unit; I guess some people called it huff and puff.

Q We're talking about the same type of system, where they -- where the injection well (unclear) to the producing well, you--

A No --

Q -- pump in water, shut it down, then pump it back?

A No, we didn't do anything like that. We just did cyclic waterflooding, where we injected at high rates for a period and then stopped injection.

Huff and puff is a process that is often employed in steaming very viscous oils where they eat up the oil region around the producing well and then back-flow the same well and there may be other places where something has been tried for injecting into the same well and producing back but that was not what this was. It was just cycling. It was on and off water injection and it was only applied for -- to this particular area for a matter of three or four years. It was a very unsanitary way to operate an oilfield, because the -- with production rates of a well changing drastically in a matter of a week or so, why, the pumping units weren't balanced right and everything else, so this was what was really a large scale experiment.

Q I see. Well, my recollection -- what I'm trying to do is compare what I thought was a Humble system of injecting water into parts of the Spraberry and and shutting in for a period of a month or so and then those same wells actually are producing wells, pumping back.

A I don't think anything like that happened. I think that they were doing about the same thing that we did in this part of the Driver Unit, because we had lots of talk across the backyard fence.

Q My association is only marginally with the Spraberry.

A Yes.

Q That's why I wanted to get some clarification. I appreciate that.

A Yes. No, I don't believe that there was any attempt to inject water in a well and then backflow the same well.

It really was cyclic operation.

Q And one other question, would you like to hazard a guess on whether a -- do you think Gavilan would benefit from some type of a waterflood similar to the Spraberry?

A Without -- there is no way to answer that. I have no basis on which to make a conclusion.

In fact in the Spraberry, parts of it responded moderately well to waterflooding; other parts of it, even within the Driver Unit, did not. In fact, a paper, a fourth paper on the Spraberry that was in the packet that is in evidence, it has the data from that.

The first area, which is -- of which

this demonstrate of performance is part of what I discussed, worked quite well. We went northeast and southwest along the fracture trend and added additional areas and they worked moderately well.

We went southeast from all of that and there essentially was no response for the remaining half of the field, we didn't -- or the unit -- we gave it not consideration whatsoever. And some of the units operated by other companies, one or two of them worked fairly well; some others just worked very poorly.

So it's only parts of the Spraberry in which this imbibition process was effective and extrapolating to a totally different formation, I have no way of knowing. I don't even know whether a Gavilan core with oil in it put in a beaker of water would expel oil. That's one of the things we tried on West Edmond. It's carbonate. It's not a strongly water-wet formation. We put a core full of oil in a beaker and it sat there for a month and there was never a drop of oil came out of it.

MR. LEMAY: Mr. Chavez.

QUESTIONS BY MR. CHAVEZ:

Q Mr. Elkins, in one of the papers as part of the exhibits, it's titled Water-imbibition Displacement-A Possibility for the Spraberry. It was presented in 1952;

however, your project in the Spraberry wasn't started until ten years later. Was there a reason for that?

A Well, there were -- there were about three steps in this. This paper was presented in '52. I think it was in about 1954 that Atlantic conducted a partial 5-spot or half of a 5-spot pilot test. It was sometime later, probably '55, '54 or '55, that Humble conducted their pilot test that was pretty, highly successful, that one 5-spot pilot test.

We started negotiations to unitize the Spraberry for a waterflood in 1957 and it took till 1961 to put the Driver Unit together and we got that waterflood starting in a reasonable number of months after the unit was formed.

I guess the easiest thing to explain the tine lag is that it just took that long to get enough people convinced that it was worth trying, and then after we did it, many of them decided it wasn't worth trying.

Although -- although the waterflood that we conducted in a part of the Driver Unit was an economic success. We made money. We made not a lot and I think if it were -- I don't know that it would measure up to many corporate standards of rates of return now, but it was a profitable operation and it did increase recovery of oil, which is a very important function, but it most certainly did not live up to the -- I'm going to call them hopes, not expectations. I was the witness putting on the testimony on behalf of the Driver Unit, and we (not understood) that if we took the results of the Humble pilot test, that we could recover 1500 barrels an acre. I also testified that it would be an extremely economical process if we got 500. Well, we didn't even get that but we did make enough to pay the investment and operating costs for the waterflood we did get.

Q One last question, imbibition is described in the literature as presented in the exhibit, seems to indicate that an oil saturated or saturated type of core soaks up water and therefore displaces oil; however, it's been presented earlier in Mr. Hueni's testimony that imbibition is described as a different process where a void has been partially emptied of oil and then oil goes back into it, but I don't know if there's any change of gas/oil ratio --

A Well --

Q -- or maybe I misunderstand it. What's --

A No.

Q -- what 's the difference between those two individual processes?

A The physics are the same. What Mr.

Hueni was talking about is that you have a portion of the matrix that has free gas saturation in it along with some oil saturation and with water saturation and if you stop expelling oil out by a gas drive, then the rock is oil-wet as compared to gas, so that it will tend to -- the blotter action will soak up oil.

What the Atlantic people described in your exhibit illustration was that the Spraberry rock is a stronger blotter for water than it is for oil, so that if you have a rock that has got connate water saturation in it and full of oil, and you put water on the face of it, it will soak up water and if it were completely liquid filled the only way that could happen is for oil to be removed and it comes out in counter-flow in opposite directions.

Q Can this imbibition be quantified?

A Not really.

Q Thank you.

MR. LEMAY: Commissioner Humphries.

QUESTIONS BY MR. HUMPHRIES:

Q I have a question on your concept that the bulk of the oil lies bulk of the oil that lies in the matrix and I think you're assuming also that there are the microfissures and getting into the large fractures, and so on. What I have a hard time understanding is, do you -- I guess I don't understand, so I'm going to ask you the question.

Can you explain to me how that could be 100 percent one way if we have a three dimensional fracture system and that with the migration of the gas and the liquid, how come it can only be one way? It's hard for me to conceive that that can't be moved both ways, because of the interconnections in a three dimensional plane?

A Well, I think the, if I understand your question well enough, and I appreciate the difficulty of conveying these concepts to somebody who hasn't lived with it for years, but if we look that we have a block of this matrix rock and that may have microfractures in it, but it's divided up by larger fractures, and if we inject gas into it, the gas is going to flow most easily around all surfaces of it, so there is nothing that is happening that wants to make that gas jump into the middle of that block and blow oil out.

Now, in the Spraberry waterflood test, the cycling waterflooding, we were injecting water at very high rates and it washed almost all the oil out of the fractures, but we were injecting so fast that we were building the pressure up so what was then going in from all surfaces of each one of these blocks of Spraberry sands and then when we stopped water injection, put the wells back on production and then we were now operating by expansion of the rock and probably mostly liquids, then it was more oil came out than water, because the blotter action withheld the oil -- I mean withheld the water to some degree and the oil came out.

The process with gas and oil is the same thing; that there, why, the rock is oil wet in comparison with the gas and it -- the blotter action tends to hold the oil back.

If you increase the rate of gas flow, then the friction drag tends to partly offset that blotter action and let more of the oil be expelled.

Q I think I can understand the theory a bit in maybe this first part where the unequal pressures by lowering the pressure in the fracture areas would obviously make it easier for the matrix production or contribution to be delivered to the fractures.

At some point, though, it strikes me that that can no longer be 100 percent one way. Is this not only primary but a continuing and permanent condition of the matrix contribution in a field like this or a pool like this or formation like this, I guess.

A Well, again, in West Edmond in the -- some of the areas as it went clear to the end, the gas/oil ratios increased into 2 and 3 and 400,000 cubic foot per barrel ratio and the oil production of the wells declined to just fractions of a barrel and then they really became flowing gas wells because the formation pressure was already down to a couple of hundred pounds or so.

And so it did continue and there just wasn't any more oil coming out at the end because then the oil saturation within the matrix had been reduced to a point that it wouldn't flow, at least with the combination of available pressure differential being opposed by the capillary end effects.

Q Thank you.

MR. LEMAY; Additional questions of the witness?

If not, he may be excused, and we shall reconvene --

MR. PEARCE: One matter before -- briefly, I'd like to assure the Commission that Mr. Elkins can spell. I'm looking at the bottom of what we marked as Exhibit I think it's Thirty-seven, the results of laboratory experiments, and I notice that we misspelled the name of Mr. Elkins paper and I apologize to the author and let the record reflect that we know how to spell performance.

MR. LEMAY: We find incompetence in many areas.

Any additional questions of the witness? If not, he may be excused. Thank you, Mr. Elkins.

MR. ELKINS: Thank you.

Tomorrow morning at 8:30 we'll reconvene.

(Thereupon the evening recess was taken.)

CERTIFICATE

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY the foregoing Transcript of Hearing before the Oil Conservation Commission was reported by me; that the said transcript, contained on pages ~~2~~ 249 through ~~245~~ 510, inclusive, is a full, true and correct record of this portion of the hearing, prepared by me to the best of my ability.

Sally W. Boyd CSR