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

21 & 22 August 1986
27 August 1986

COMMISSION HEARING

VOLUME IV

IN THE MATTER OF:

Application of Jerome P. McHugh and Associates for an amendment to the special rules and regulations of the Gavilan-Mancos Oil Pool...	CASE 8946
and	
Application of Benson-Montin-Greer Drilling Corporation for the amendment to the special rules and regulations of the West Puerto Chiquito-Mancos Pool ...	~~CASE~~ 8950

BEFORE: Richard L. Stamets, Chairman
Ed L. Kelley, Commissioner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Oil Conservation Division:

Jeff Taylor
Attorney at Law
Legal Counsel to the Division
State Land Office Bldg.
Santa Fe, New Mexico 87501

A P P E A R A N C E S

For Jerome P. McHugh

W. Thomas Kellahin
Attorney at Law
KELLAHIN & KELLAHIN
P. O. Box 2265
Santa Fe, New Mexico 87501

For Mobil Producing:

W. Perry Pearce
Attorney at Law
MONTGOMERY & ANDREWS
P. O. Box 2307
Santa Fe, New Mexico 87501

For Koch Exploration

Ernest L. Padilla
Attorney at Law
PADILLA & SNYDER
P. O. Box 2523
Santa Fe, New Mexico 87501

For Mallon Oil, Mesa Grande, and American Penn

Owen M. Lopez
Attorney at Law
HINKLE LAW FIRM
P. O. Box 2068
Santa Fe, New Mexico 87501

For Amoco Production

Kent Lund
Attorney at Law
Amoco Production Company
P. O. Box 800
Denver, Colorado 80201

For Benson-Montin-Greer

William F. Carr
Attorney at Law
CAMPBELL & BLACK P.A.
P. O. Box 2208
Santa Fe, New Mexico 87501

For Dugan Production:

Robert G. Stovall
Attorney at Law
Dugan Production Company
P. O. Box 208
Farmington, New Mexico 87499

For Koch Exploration

Robert D. Buettner
Attorney at Law
Koch Exploration Company
P. O. Box 2256
Wichita, Kansas 67201

For Meridian Oil

Paul Cooter
Attorney at Law
RODEY LAW FIRM
P. O. Box 1357
Santa Fe, New Mexico 87504

For Hooper, Kimball and Williams

Greg Owens
Tulsa, Oklahoma

I N D E X

I N D E X CONT'D

E X H I B I T S

I N D E X CONT'D

THEREAFTER at the hour of 8:25 o'clock a. m. on the 27th day of August, 1986, the hearing was again called to order in Committee Room 339, State Capitol Building, Santa Fe, New Mexico, before Chairman Richard L. Stamets and Commissioner Ed Kelley, at which time the following proceedings were had, to-wit:

MR. STAMETS: The hearing will come to order.

I tried to contact all of the attorneys yesterday and advise them of the plan for today but just to reiterate that, we will finish this case today.

We are going to allocate three hours for the pros, those who are in favor of the applications, which they may use in any way they see fit, putting on direct testimony or cross examination.

We'll allow three hours for the opponents, which they may use as they see fit.

We're going to start out this morning with the pros and let them do their thing. This will also, then, provide for some slippage in case the Commission wishes to allow some additional time for both sides.

Also we anticipate not more than fifteen minutes a side for closing arguments, unless either side chooses to use some of their three hours for closing arguments instead of either direct testimony or cross examination.

Are there any questions?

MR. LOPEZ: Well, Mr. Stamets, maybe just an observation.

I realize this is the way you want to do this, but it was suggested that perhaps a fair allocation of time would have been, since there seems to be three different positions, one which the McHugh-Greer camp is promoting, the one that the Mallon-Mesa Grande camp is promoting, and the one that the Mobil camp is promoting, which takes in three different spectrums on the scale, and therefore two hours and two hours and two hours would be more appropriate.

But knowing that yesterday you set the rules to begin with, we can live with them.

MR. STAMETS: Thank you, we appreciate that.

With that, then, we'll begin this morning with either Mr. Kellahin or Mr. Carrs.

MR. CARR: Mr. Stamets, it's my understanding that we may use our three hours anyway we choose and in any order that we choose.

MR. STAMETS: Correct.

MR. CARR: So initially we will call Albert R. Greer for rebuttal testimony.

I would request that the record reflect that Mr. Greer has previously been sworn and remains under oath and that he has been qualified as an expert witness in the field of petroleum engineering.

ALBERT R. GREER,

being recalled as a witness and having been previously sworn and remaining under oath, testified as follows, to-wit:

REDIRECT EXAMINATION

BY MR. CARR:

Q Mr. Greer, you were present last Friday and heard the testimony of Mr. Hueni, did you not?

A Yes, sir.

Q Do you agree with the interpretation of the Mancos formation in the subject area as presented by Mr. Hueni?

A No, sir, I do not.

Q Could you briefly summarize the interpretation presented by Mr. Hueni at that time?

A Mr. Hueni made a number of mistakes, Mr. Chairman, that led to his mis-interpretations and to begin with, he had the wrong bubble point and from that worked up a projected performance of the reservoir and came up with the -- the conclusion that the reservoir was performing as a solution gas drive reservoir would insofar as the pressures were concerned but his -- the gas/oil ratios of the pool were less than what he would have calculated and accordingly there was something strange going on.

And so he, having basically the wrong information to start with, he arrived at basically wrong interpretations.

In the course of this he found some anomalies in analyzing the behavior of the reservoir and -- and he took these anomalies as supporting his basic premise and he felt all along then that he was building on his case and that -- that the wrong interpretations, the wrong information, then, resulted in the wrong conclusions.

Q Now, Mr. Greer, what is the significance, actually, of using the wrong bubble point?

What impact does this have on the data?

A It has a very significant impact in that it shows the difference in the calculated gas/oil ratio and the observed performance of the pool to be a significantly different amount than it really is, and that then makes him feel that he has to -- to reach down deeper to find some kinds of strange behavior to explain this.

Q What was the basic information that Mr.

Hueni was relying on in calculating what the bubble point was?

A He makes reference to some bubble point -- some samples and reservoir fluid samples. He concludes that they were not accurate and so then he takes some separator samples and estimates the bubble point from that, a very inaccurate, if I might say, way of determining the bubble point, particularly in this stratified reservoir in which there are free gas stringers and can contaminate the samples such that a separator sample can -- may not, and probably does not represent the fluids which existed and would give that kind of a bubble point.

Q What kind of information or samples did you use in determining what the bubble point should be in this reservoir?

A Mr. Chairman, we went to great lengths to -- to get very accurate reservoir samples in order to determine the bubble point and we obtained one sample high on the structure, we determined from another one low on the structure, bubble points that checked within just a few pounds of each others; no question that we had accurates bubble point information.

Q And when were these samples actually taken properly?

A One, I believe, was in 1962, and then another one a couple of years later; three years later, maybe.

Q Will you review these samples and then your calculations with the Commission as part of your testimony this morning?

A Yes, sir, I'll review in detail how we determined the true bubble point pressure and how Mr. Hueni made his mistakes.

Q Now, Mr. Greer, did you also hear Mr. Hueni's testimony concerning oil and gas segregation in the reservoir?

A Yes, sir.

Q And have you reviewed his presentation?

A Yes, sir.

Q In your opinion was the presentation based on accurate information?

A No, sir.

Q And how so?

A Well, he used, as I mentioned a minute ago, the fact that the -- the gas/oil ratio measured in the pool was substantially less than what he would calculate for a solution gas drive reservoir. So we felt like there had to be some other strange reason for this. He found some anomalies in some -- the production behavior of some wells that seemed to lend credence to his supposition, and we just have to recognize, Mr. Chairman, that Mr. Hueni just did not have time to make the study necessary to understand this reservoir.

So he found some anomalies. He, without checking the anomalies to see if they really, truly existed, he just accepted them, made his determination that, yes, there is something strange going on, and so he just reaches down into the depths of the mysteries of these underground rocks and comes up with a bizarre interpretation that best can bes described only as -- as outrageous.

Q Now, Mr. Greer, will you review this presentation in detail as part of your case today?

A Yes, sir, I'll go every point -- over every point he discussed.

Q Now, Mr. Greer, as part of his case Mr. Hueni discounted the effect of the reliability of the interference test information that you've obtained.

A Yes, sir.

Q In your opinion was his approach to this test or this type of testing accurate and appropriate?

A No, sir, Mr. Chairman, it's pretty clear that -- that Mr. Hueni did not understand the type of interference testing we conducted.

We will explain the mistakes he made in those respects in detail.

Q Were you also present for the testimony presented by Mobil concerning the core data they have obtained in the two porosity systems which they assert is working in the reservoir?

A Yes, sir.

Q And in your opinion was this an accurate interpretation of the reservoir?

A Well, it doesn't -- it doesn't fit the general interpretations, Mr. Chairman, of -- of what geologists and engineers now consider a naturally fractured reservoir. He has eliminated the natural fractures in his calculations, apparently, and is dealing only with what must be induced fractures or fractures great distances apart, and as a consequence, then, by his calculations he feels that it's necessary to pull the pressure down in the fracturesa in order for the matrix, if there is any matrix, which I seriously doubt, to produce.

Now if the fractures are closer together, as they are normally in a fractured reservoir, then the matrix makes itself known, so to speak, early in the life of the reservoir. And so in the instance of Gavilan, if there is -- if there is matrix porosity and it's fractured, we know it's fractured, then the matrix is contributing now just as much as it ever can in respect to the pressures that exist.

And so, when we interpret the reservoir

behaviors now in terms of pressure decline versus cumulative production, we're seeing whatever is there in the fractures, in the matrix, whatever, and the net of this, Mr. Chairman, is that wherever the oil is coming from, the reservoir is in trouble.

Q Now, Mr. Greer, as time permits, will you have technical testimony concerning the possibility of matrix contribution in this reservoir?

A Yes, sir, if we have time we'll go into that.

Q Now, have you prepared certain exhibits for presentation here today?

A Yes, sir.

Q At this time if we could pass out Exhibit Number Six, please.

Now, Mr. Greer, referring to Benson-Montin-Greer Exhibit Number Six, before we go into the particular sections of this exhibit, could you generally characterize the analysis made of reservoir by Mr. Hueni?

A Yes, sir. This Exhibit Number Six will cover just a part of Mr. Hueni's testimony and it sets out how Mr. Hueni came about making his mistakes and -- and they're understandable, Mr. Chairman. I don't want to imply in any way that I think Mr. Hueni is not capable; he's obviously a capable, talented engineer, but he made mistakes;

mistakes that I very well could have made myself thirty years ago, before my hair got so gray.

They just come about and once you get started down a line and you have laid before you a lot of information, you don't have much time to work with it, you make a quick analysis of it. You jump, and that's the only word that can explain it, you jump to a conclusion, and then unconsciously as you develop information you accept the things that embellish your initial conclusion and you tend to kind of set aside things that might not contradict it, and it's not a deliberate thing. It's just a natural way that we humans work as we work on a problem.

Q Now, initially let's look at the calculated GOR and before we get to Tab A in Exhibit Number Six, there are certain documents.

I direct your attention first to the first blue page after the title page and ask you to identify that and review it, please.

A This is a copy of the gas/oil ratio and production history from Mr. Hueni's exhibit and which shows a very flat gas/oil ratio curve for the pool during the years 1985 and '86, when in fact the gas/oil ratio is declining rather fast at the end of this period.

Q And the notations on that are your handwriting --

A Yeah, my handwriting where I note the (unclear).

Q All right, would you go to the next page, please, and identify that?

A The next page shows the detailed calcula tions which our engineer made in arriving at the -- what might be a representative gas/oil ratio for the -- for the reservoir. In order to do that it was necessary to deduct the two wells which we feel would have, if their information is included, the No. 1 Gavilan and Gavilan Howard, because of communication from the Dakota on one and just where the gas came from on the No. 1 Gavilan, we don't know, but they're wells whose information needs to be deleted from the pool total in order to arrive at some kind of a representa- tion of what the gas/oil ratio is really doing in the oil part of the reservoir.

Q Now if you go to the next document in this exhibit, which is a graph, please identify that and just briefly review it.

A All right, this is a copy out of Section D of McHugh's Exhibit Number Three in this case, and -- and the figures which our engineer came up with checks exactly with -- with McHugh's work in this calculated gas/oil ratio, and this shows the rapidly rising gas/oil ratio in the pool and more accurately depicts what's going on than what Mr.

Hueni was using.

Q Now this data goes through what period of time, Mr. Greer?

A I believe it ends about May of this year.

Q And that's what Mr. Hueni's exhibit also depicts?

A I believe that's right.

Q All right, now let's go to the pink sheet and I'd ask you to identify that and I think it's important to note that you have penciled certain notations on this exhibit, is that correct?

A Yes, sir. Basically this is one of Mr. Hueni's exhibits, pages out of his exhibit. There are some pencil notations on there showing, first starting on the lefthand side, the vertical penciled line, between the two vertical penciled lines, says it 1,750,000 barrels produced from the bubble point, and I believe that the bubble point is kind of hard to read in this scales, but it appears from the way the pressure dropped rather steeply at first, that Mr. Hueni, I believe, has assumed that that is the bubble point, that first solid dot on the -- on the pressure line.

From there over to the 1,950,000 barrel point there's then a million and three-quarters barrels of oil produced during that period of time.

You can see how Mr. Hueni's pressures fit the observed pressures, and it's my understanding that he used about 100,000,000 barrels of oil in place to calculate this.

When I used 100,000,000 barrels of oil in place, the same relative permeability ratio, and PVT data from the Loddy or the Canada Ojitos Unit, either one, they're very -- fairly close together, I get a much lower calculated gas/oil ratio.

Now, the difference, the difference may be, and it's a significant difference, Mr. Chairman, it's halfway between Mr. Hueni's projected point and his actual gas/oil ratio, and it's this big difference that leads Mr. Hueni to the conclusion that there's something strange going on in the reservoir.

So if the gas/oil ratio, the projected gas/oil ratio were actually lower than he has it, then he really doesn't have a strange reservoir, or a strange situation to deal with.

Now, the actual gas/oil ratio is probably -- would be higher than is shown here for the reason that part of the oil is still under-saturated, new wells are coming on line, and so although this -- this graph reflects the reservoir performance of the pool as a whole, it's really distorted in that as new wells come on, if they come in with a -- or they're drilled in an area where one of these stratified sections has gas in it, it will kick the gas/oil ratio up, a well that comes in with the -- fairly close to the solution gas/oil ratio below the bubble point will distort it down.

So it's very difficult, really, to say from a curve like this that the performance is or is not following what would be expected for a solution gas drive reservoir of this type.

Now, as indicated, the difference between the red dot, Mr. Hueni's red dot and my blue dot, might be because he's used different PVT data than I did but I just can't think that that's the difference and we'll get to that in a minute where I compare it.

The Canada Ojitos PVT data and the Loddy, the difference I would think there is about the same as I would expect from what Mr. Hueni's used, and so I conclude that in addition to that, that the gas/oil ratio line is probably not very accurately calculated and the reason I say that is Mr. Hueni notes that it's calculated by the Horner method and there's nothing wrong with the Horner method if you use it correctly for this situation.

Here, where we're dealing with rapidly rising changes in the relative permeability ratios, for small differences in oil or total liquid saturation, requires a more accurate treatment of this problem than you ordinarily can get with the Horner method if you use big steps.

With the Horner method you need to use small steps to get it. Even the way I calculate it, I would use at the most that big a step the first time, and when I'm talking about that big a step, I'm talking about where the gas/oil ratio point breaks from level to its first increasing point at about 1,250,000 barrels, and the problem here is the compounding of problems.

First he uses the Horner method. Second he uses a computer, so then he had compunded the inherent inaccuracies of the Horner method with the errors that the computer is going to bring in and the errors that the computer brings in is it averages arithmetically between the two points and -- and the rising ratio of permeabilities is on a logarithmic scale. The end result, then -- well, then another thing. He uses too few points to define for the computer the relative permeability ratio. He shows on his information how -- the information he gave the computer.

What that means is that if at some particular point the computer is seeking its trial and error method of reaching a point, if that's close to the points he put into the computer, then it's fairly accurate, but if it's in between, then the computer picks up a higher KgKo ratio than really exists, and so that tends to give a higher gas/oil ratio. If the first point is off, then the amount of gas taken from the reservoir is off, the liquids left in the reservoir is off, this is all in the calculation, and then the end result is too high a gas/oil ratio, and so when you compound all of these problems, I'm not surprised that the gas/oil ratio calculated here is higher than it would -- should be.

Now, if you take into account the probability that the bubble point is much lower than what Mr. Hueni used, then the shift of the curves, of the computed curves, or the field performance curves, are to the left and John Roe brought this out in his testimony in pointing out the first time that he looked at the solution gas drive recovery, that, yes, there's a problem here and that is one of the probable solutions in addition to the fact that the gas/oil ratio is not fairly representated by taking the average of everything.

So, the net of it is, then, that I need to leave it clear to the Commission that there is a option to Mr. Hueni's interpretation. The option is that the reservoir is performing like you expect it to.

Q Now, Mr. Greer, you've just identified the document behind Tab A and then moved right into the document behind Tab B in this exhibit.

A This is -- under Tab A is just the reservoir fluid study of the Loddy and which I used to make a comparison with Canada Ojitos recovery.

Q Okay. Now going to Tab B, would you just identify the first document behind that tab?

A That's the relative permeability ratio curve which we've discussed earlier in this hearing.

Q And now go to the next sheet, please.

A The next one is the expanded curve, the same information as is shown by the dashed line on the blue sheet expanded to a wider scale and brought down to .001 relative permeability ratio, and the reason I've done that is to have a more defined line for comparing the difference in calculated performances with the Loddy PVT data and the Canada Ojitos Unit PVT data.

Q All right, now please go to the yellow or orange sheet that follows that and identify that and review it, please.

A This next sheet shows the comparison of the projected performance curves, using the Canada Ojitos data and the Loddy data, and points out that there's really not a lot of difference early in the life of the pool. The ultimate recovery is about the same. There'll be a higher gas/oil ratio, but the point is it's not significantly greater as would appear from Mr. Hueni's calculations and so, although I've not calculated the performance using Mr.

Hueni's PVT data, I just have the feeling that there's no way that there could be that much difference if they're properly calculated.

Q Now, moving from that data and going to the information behind Tab C, would you review that information and indicate how it relates to the calculation of relative permeability?

A One way, Mr. Chairman, to tell whether this reservoir is performing in one respect as a solution gas drive reservoir, which I've not had an opportunity to -- to recognize much gravity drainage, is to take a well that produces -- it produced a significant amount of oil, has a rather large drop in pressure so that we have the maximum range of pressures and hopefully, the maximum change in liquid saturation in that area, and from that, the producing information from a well such as that, we can then calculate the actual relative permeability ratio as it applies to that well, and that's what I've done here.

The first sheet show show oil to gas viscosity ratio from the Loddy data, plotted on the next graph, the white sheet. Then on the gold colored sheet we show what the liquid saturation would be at any particular reservoir pressure depending upon the bubble point.

The first horizontal scale shows for a 1500 pound bubble point; the second for a 1550 pound bubble point; the bottom one for a 1600 pound bubble point, and I used that information to go to that set out under Tab D.

Q Okay, will you now identify that and then review what that calculation shows?

A This shows the calculated relative permeability ratio taken from McHugh Native Son No. 2 Well for the four periods, 1 December '85, February, April, and June '86.

We take into account the fact, Mr. Chairman, that there is about a 300 foot difference in sections from the top possibly producing zone to the bottom one, which is roughly 100 pounds differences in the upper to the lower part of the pay zones and we don't know which, if any, is contributing -- or which of the zones are contributing the most of the production, but there just in this one well alone and the fact that we have the different zones, makes it impossible to tell what the liquid saturation would be in any one of the zones for a different pressure, and so what I've done is to cover that range and we plot that range. And the range is shown -- in the middle of the sheet is shown the relative permeability ratio for those producing conditions. The bottom three horizontal lines show the liquid saturation depending -- for each of the bubble point conditions. At the bottom of the page is shown the simple formula by which that's calculated.

Q Now go to the graph on the next page and discuss that.

A The next page is the same as the early one we looked at of the expanded graph, except I've left out the lower straight line which covers a lower liquid saturation, and it's on this graph, then, that I plot the data we just calculated, and that's shown on the pink graph.

On the pink graph we show for December '85 that -- that the liquid saturation would be 100 percent if the bubble point were 1500 pounds. The pink sheet is for 1500 pound bubble point pressure.

Then for February the range runs from about 99 percent to 100 percent.

In April it runs from about 98.3 percent to 100, and then in June, about 97.4 percent to about 99.5 percent.

And on the next page we see where the range of data would fall if the bubble point were 1550 pounds.

And then on the yellow sheet we show what the range of data would be for 1600 pound bubble point.

Q Now what do these three graphs actually show?

A What these show, Mr. Chairman, is that there is no reason to believe that insofar as this well is concerned, and I grant you it's very difficult to find characteristic wells which represent the average of the pool to be expecteds, but this well has produced a significant amount of oil, has the biggest drop in pressure, and is the one that I would think would be most apt to represent conditions, and if the relative permeability ratio for this fractured formation is as we think it is, if the bubble point is in the range that I think it is, then there is nothing unusual about the way this reservoir is performing as far as solution gas drive is concerned and there is no need, Mr. Chairman, to go to some strange behavior to explain why the pressure and production data do not fit Mr. Hueni's curves.

Q Now, Mr. Greer, would you go to the document contained behind Tab E in Exhibit Six and identify this, please?

A Yes, sir. Mr. Hueni sets out here, this is a sheet that -- out of his exhibit. The highlighted language says that the remaining samples, and he's talking now -- see, what happened, Mr. Chairman, Mr. Hueni was provided sample data on three wells, two were taken by the McHugh people, one that was taken by our company in the Canada Ojitos Unit. The two taken by McHugh were in the Gavilan Pool.

The information on one of the wells was obviously not good and on the Loddy there was a question about --about that information, and I understand his concerns about that. I have concerns abut the PVT data on the Loddy. The McHugh people, when they first told us about the samples that they took, said that they realized that he'd get some information on the reservoir, they had no bottom hole samples over there, they thought they would run out and the language they used, as I recall, was we would get some quick and dirty samples, and that's what they got. One of them was just no good at all; the other one appears to be somewhere in the ballpark, but I can understand here Mr. Hueni's reservations about that -- about the Loddy samples .

Then he says here, and we need to read this, "The remaining samples", now he's talking about the Loddy and the Canada Ojitos samples, he says, "they were both taken after significant production from their respective pools and it could not be determined if the lab reported bubble point pressure reflected true reservoir conditions or some gas evolution had occurred prior to sampling." Now that was true about the Loddy. We had no information about that, but it is untrue about the Canada Ojitos Unit sample, and you see, Mr. Hueni was in such a short time, such a short time to analyze this that he did not come to us and ask us about our sampling procedure, was it a good, valid sample, did we have any other samples, but he was at the point that he was really desperate to determine, well, what really is the bubble point, and so he goes then to separator samples, and he had to be desperate to do this because, Mr. Chairman, the -- to determine a bubble point from separator samples, you're just reaching in the bottom of the barrel for information. That's the last resort.

So it's unfortunate that he didn't have the time and no one who was helping him realized that they should have advised him to go check with Benson-Montin-Greer, they very carefully took the samples; they got some good samples. He didn't know that.

So he uses poor information to arrive at the bubble point. You need to look at how bad, how bad the information can be to use separator samples to estimate the bubble point.

Q Okay, now doing this, would you go to the next exhibit in Section E and identify that? I believe this is an exhibit we've seen before.

A Yes, sir, this is an exhibit we've seen before and about the center of it is a cross section identified from the Mallon Howard 1-A east to the Canada Ojitos Unit E-6 and down to the J-6, and the main thing I want to point out here is that the J-6 is just about the lowest well in the trough on the east side of the Gavilan nose and the low part of the structure from Canada Ojitos Unit.

And why this is significant is because in this stratified reservoir there's free gas, we know at least in what we call the gray zone, and we'll look at that cross section that next falls.

Q Okay, and that's the next exhibit in -- or document in Section E of Exhibit Six.

A Now, Mr. Chairman, we're talking about the bubble point but we don't have much time and I need to talk also about stratification, so if you'll bear with me I'd like to jump to stratification now so we won't have to come back to this exhibit.

The three main producing zones that we have in West Puerto Chiquito and Gavilan are the A, B, and C zones. The gray zone is one that kind of comes and goes and in my view from what we've seen so far is just probably gas productive.

These zones are stratified, Mr. Chairman, and they may, as indicated in my initial testimony, be tied together in a place or two by faults. There are not very many faults in the pool. McHugh's structure map by Dick Ellis is the only one that I remember seeing that showed any -- any identifies faults. So in general, in general the -- when individual wells are produced, completed, they produce as stratified zones.

We have on numerous occasions, Mr. Chairman, completed a well in the bottom zone, in the C zone, and with that thick, nonproductive section between the brown and the green zone, we have found separation. We've gone back after packing wells and found that the zones are separated.

We've even found separation, Mr. Chairman, between the A and the B zones where the perforations were as close together as 20 or 30 feet. We have, for instance, fraced the A and B zones together, put a bridge plug between the two zones, produced the well for two or three years, production rate ten or fifteen barrels a day; drilled out the bridge plug and picked the production rate up to 40 or 50 barrels a day. No question, Mr. Chairman, the zones are stratified. There is no vertical communication as Mr. Hueni has suggested.

Now, to talk about the bubble point, we show here the perforations through small horizontal lines on the insde of each of these logs.

Mallon has perforated the zones pretty much from a gray zone down to the unidentified zones at the bottom. The uncolored zones at the bottom are, the top is the Sanostee, the bottom is the Niobrara, base of the Niobrara silt.

Sometimes they produce very small amounts of oil but very small.

When Mallon perforates most of their section, in our offset well we feel like we're obligated to perforate most of ours for legal if no other reasons.

But when we get farther off to the east where we're not directly offset, we perforate the zones which are reasonably thought to be productive, which is A, B, and C zones, a little bit down in the Sanostee and the basal Niobrara.

Now, when we completed the E-6, the center well, we did not want additional gas there. We were planning to use this as an interference test well. We didn't want to perforate the gray zone. We realized Mallon had perforated it but to protect our interest we would need to have a well somewhere over there that would produce the gas out of the gray zone.

We left that until we drilled the J-6, the well on the right. We perforated the gray zone here along with the other. This well then showed about 400,000 feet of free gas out of the -- out of the gray zone, and how that -- and so now we looked at what would happen if we took a separator sample on the J-6 to estimate the bubble point. And I show that on the --

Q And that's the document in yellow behind Tab E?

A Yes, sir, and this is one of the old, twenty-five year old methods of correlating bottom hole sample data. They have more accurate information now but in general we can see from this information how if, in taking a separator sample, you have commingled with the oil some free gas from one of these stratified zones, then --

Q Go to the -- go to the graph now behind it and show -- review for the Commission what this shows about the reliability of separator samples.

A The -- the -- we start on the lefthand side of the graph and start with the green line. The green line starts at a gas/oil ratio of about 500 cubic feet a barrel, drops down vertically to the 40 or comes over horizontally to about the 0.7 gas gravity line, drops down to the approximately 40 degree oil line, goes over horizontally to approximately the 150 degree reservoir temperature, and you come up with 2000 pound bubble point. Now, this is approximately what we had in Canada Ojitos, about 480 cubic feet a barrel and true bubble point's about 1520; this shows it within, you know, 4-or-500 pounds, not too bad for a rough guess.

But what would happen if we had a high gas/oil ratio well, free gas mixed in the separator samples, and the first sample we had on the J-6 would have been 5000 cubic feet a barrel. The chart doesn't go that high to follow it over to the righthand side but we just go up to about 15-or-1600 cubic feet a barrel and what would it show.

Well, we follow the same path over to

0.7 gravity, down to the 40 gravity, over to the 150 degrees and we find a bubble point of 5000 pounds.

Now, this is the problem that you have, Mr. Chairman, in a stratified reservoir mixing oil from an oil zone, gas from a gas zone, and trying to estimate a bubble point. So Mr. Hueni used the most unreliable method available to estimate the bubble point.

Q All right, would you now go to the log section which is the next page behind Tab E?

What does this show?

A This shows what we found in a number of wells cored in the basin, not in this area, but in the same general section of the Mancos on the west side of the basin. Cores were analyzed about fifteen years or so ago.

We found that we could -- that we had very little reliable information we could get from cores, but what we did find was -- well, mainly we found that in their analysis and their recording of the samples that they took out not only what might be oil in the -- in the effective hydrocarbon pore space, but they took out the kerogen of the shale, just like oil shale that they have in Colorado for -- that they run through the plants in order to get oil out of the oil shale. In the core analysis process they took out the kerogen, they took out the water hydration, and so it's really difficult to determine from a core analysis in this formation what, really what's going on.

But one thing we did find, one thing we did find is that whether it's oil kerogen or whatever that you took out of the shale, there isn't any of it when the resistivity gets down around 15 ohmeters. Now this was for -- and even as high as 30 ohmeters we'd have to go before we find the significant amount of oil.

So we find in these zones, the separations of the producing zones, these low resistivity shales, and they just don't have any oil in them. If they have any oil it's just by happenstance of a fault or a fracture that's come down from above, and we note, for instance, that Mobil in its core analysis didn't even analyze these shales between the producing zones. This is just some more of the evidence that shows that the zones are stratified and not vertically connected.

Q Mr. Greer, what does this tell you about the concept of one 600 foot producing interval?

A It's just impossible, Mr. Chairman, there's no way it can beds.

Q Now, Mr. Greer, you talked about samples that you had taken early in the life of the reservoir. Would you go to the information contained behind exhibit or Tab F in Exhibit Six, identify this, and then very briefly summarize what this information is.

A This - this shows the sample that we took, the bottom hole sample on the discovery well in the West Puerto Chiquito Pool.

One of Mr. Hueni's statements was that the samples had been taken after substantial amount of production had been had from the pool and they couldn't tell whether gas had evolved from the sample or not.

We show here the drilling history when this well was spudded, the complete drilling report, some of the core descriptions and over on page five of the green sheets we had drilled this well with air and we found oil in the C zone at -- on August the 10th, 1962.

Three days later we ran tubing and shut the well in.

We blew the well for another day.

A total of about four days of production was taken from that well before it was shut in. Well made about 15 barrels a day and then we shut it in to determine a -- get a bottom hole sample.

We put the well on production about two months later in October and you see on page six of the green sheet where it's capable of something like 15 barrels a day.

On the pink sheet following the green sheets there's a bottom hole pressure survey for this well we took at the time it was shut in.

The pressure build-up passed what -- we did not know or have any idea at that time what the bubble point pressure was. We got 1520 pounds, which it reached that in about September the 4th. Then for another two or three weeks the well was shut in to stabilize and at 1635 pounds, according to the dead weight test that we used at that time for calibrating our logs.

We later changed the different dead weight test to determine that probably that was closer to 1620 pounds or somewhere in that range, 1620 to 1635.

We then took a bottom hole sample that's shown here on the yellow sheet following that and that bottom hole sample shows on the fourth yellow sheet, the bubble point pressure of 1524 pounds at 152 degrees Fahrenheit. That we consider, Mr. Chairman, was a good sample.

Now, any engineer is a little concerned about a bottom hole sample where the well productivity is only 15 barrels a day and even though it was allowed to build up slow, there -- you wonder just a little bit about it, and so you like to have confirmation of it.

So we confirmed the bottom hole sample that was good by taking another one and the next --

Q Is that information behind Tab G?

A Yes, sir, behind Tab G. What we show here on Tab G when this particular well was drilled, the L-

11 we called it at that time -- or 12-11 at that time and now the L-11 -- and the well was completed as we show here on the third blue sheet in November of 1964.

The well was produced then for several months at about 500 barrels a day. We got -- we fraced the well with oil but I think we recovered probably in that length of time, oh, maybe 100,000 barrels.

We know that we had an uncontaminated reservoir to deal with, but in order to be certain that we could get a good bottom hole sample from this well, we pulled the tubing up to 2000 feet, bottom of the tubing 2000 feet from the surface, and we did that so that there's no way that the crew in swabbing oil from the well could pull oil at a faster rate, would pull the bottom hole pressure down faster than -- than -- so fast and to so low a point that it would cause gas to evolve from the -- from the sample.

And you can see that we conditioned the well for some ten days to two weeks swabbing at a rate of -- at the maximum rate of 4 barrels an hour, which would be about 100 barrels a day. The well had a PI of about 2.25 as shown on the pink sheet following at the bottom of the page, under those conditions the drawdown pressure was approximately 45 pounds and the static bottom hole pressure of about 1670, so the minimum, the minimum bottom hole pressure, Mr. Chairman, that could have existed at the time that we were conditioning this well and conditioning very carefully, Mr. Chairman, we were very careful in determining and making sure that we got a good bottom hole sample. And the closest that the pressure got to the presumed bubble point was 100 pounds.

That sample then was taken on July 1st, 1965, and on page, the third of the yellow pages, we see where CORE Lab came up with a bubble point of 1519 pounds at 162 degrees Fahrenheit. I don't know just how accurate those temperatures were that we took in those days, but they're probably somewhere in the ballpark.

So now we want to estimate or make an estimate, what would be the logical pressure for Gavilan, but just before we look at that, we have a confirmation, a confirmation that the oil definitely was undersaturated and that's shown by the second from the last sheet under this section, the white --

Q The white graph.

A The white graph. The white graph is a plot of initial pressures in the Canada Ojitos Unit versus cumulated production, and you'll note on the upper lefthand side of the graph that the initial pressure decline was at a rate of about 2650 barrels per pound.

Then at about 150 barrels it increased to

3000 barrels a pound, and it continued to increase and you can see at about a million barrels of production that the -- this coefficient had increased to 7000 barrels per pound. Now why did that increase, Mr. Chairman? It increased because the -- in this -- in this reservoir which is on an incline, the oil was undersaturated probably through most of the oil column. As oil is produced and the pressure drops, then the bubble point in a sense moves down the structure. Where it was initially 1600 pounds at one point in the structure you produce oil. The pressure drops. It drops down to 1500 pounds. It's now down to the bubble point. All the oil remaining above that part of the reservoir in the structure is now saturated. Being saturated it has a higher compressibility. Having a higher compressibility it adds that force to the overall reservoir system compressibility and then that allows more oil to be recovered per pound of pressure drop.

This confirms, Mr. Chairman, the fact that -- that the oil was understaturated.

Now this reservoir was such a high transmissibility, pressures equalizing over miles within just a few days, there's no question that this is what happened and that the oil was understaturated at about the bubble point pressure.

Q Now go to the last sheet in --

A The last sheet is a green sheet. We now estimate the bubble point for Gavilan from these bubble point pressures that we have in Canada Ojitos.

The upper line shows from the K-13 we would estimate 1524 pounds plus 54 pounds where we would estimate 1578 pounds for Gavilan.

From the L-11 we would have 1519 pounds plus 24 pounds would be 1543.

We get those differentials, Mr. Chairman, from CORE Lab's analysis of the oil as to how the bubble point changes with temperatu.e, and you can see there that we have a spread of about 30 or 40 pounds, 35 pounds.

That's a reasonable range, Mr. Chairman, for the bubble point. We think that the temperature in Gavilan is 170 degrees. That's what we're measuring now with the bottom hole pressure equipment that we're using that records temperature simultaneously with pressures.

So this is what -- what I would estimate as the range of the bubble point pressure and that checks fairly well with what we saw earlier for bubble point versus relative permeability in the Native Son No. 2.

A Do you believe you've used the most accurate data available to you to determine what this -- the reasonable range for the bubble point would be?

A Yes, sir.

Q Would you now go to Exhibit Number H, and here, Mr. Greer, I'd like to now shift your testimony to the question of the oil and gas segregation within the reservoir.

I'd first ask you, can you offer any explanation for the anomalous situation that Mr. Hueni testified to last Friday?

A Yes, sir. Mr. Chairman, you have to realize here, now Mr. -- Mr. Hueni made -- placed great significance, great significance on the fact that the Native Son No. 1, shown by the data on the yellow sheet, and the Homestead Ranch No. 2, data shown on the blue sheet, that these low gas/oil ratios, and I think he even mentioned 184 cubic feet a barrel or 180, on the Native Son 1, this is an anomaly.

Here we have a reservoir that has, I think, about 480 cubic feet per barrel (unclear) solution gas. Mr. Hueni estimates a little higher, but whichever, whichever is the case, here's an anomaly. Here's a well shows much less than that.

Mr. Hueni has interpreted that as meaning that as the well is produced, the pressure is drawn down in the vicinity of the wellbore and back out along the well's drainage radius, that as the pressure is pulled down the gas evolves from solution; then rather than coming to the wellbore along with the oil it migrates up, segregates and goes up. The oil goes up the -- the oil goes down, the gas goes up vertically but not laterally, and he says this supports his contention that this is what's happening.

Now, again, Mr. Chairman, when you're hair gets as gray as mine and you find an anomaly like this, before you use that to support a bizarre theory of reservoir performance, you look to see is the anomaly really an anomaly. Is it really there?

One of the first things we look at, let's look on the blue sheet and you see the gas/oil ratio 229 then zero then 372, then it comes down 371, 371, 371. What does that mean? Well, that means that this is before now, you see, this is before this well is hooked into the -- into the gas line, so these gas/oil ratios are estimated, Mr. Chairman, on a test that somebody's made in the field. We don't know whether it's a pitot tube test or orifice well test, we don't know what the separator pressure is, probably about 100 pounds, and the 371, 372 might be pretty good. The gas goes through the tester.

But if there's a 100 pound separator ahead of the separator, then there's about 100 cubic feet a barrel goes over to the stock tank through the air. And so the true gas/oil ratio in this instance would probably have been somewhere around 480 cubic feet a barrel, which is what the PVT data from the Canada Ojitos Unit wells would suggest.

Okay, we come down and it shows 210 in this first month. Now that's the first month that the well went into McHugh's gas system that goes into a system on which I think there are three or four other wells, and so there is the problem of allocating back to each well how much gas came from each well, and so there is an opportunity for -- for a mistake, just plain, old, human, ordinary error.

But the main thing, the main thing, and I presume Mr. Hueni didn't know this, is that these two wells are flowing wells. They're flowing wells. Now what does that mean? That means that with a gas/oil ratio of 180 cubic feet a barrel, a gas/oil ratio of 210 cubic feet a barrel, they can flow only if they've got bottom hole pressures of 2000, 2500 pounds, and that's not available.

So what's the answer? Well, the answer is that the gas/oil ratios, as shown here, are not accurate. That's unfortunate. It's unfortunate that Mr. Hueni accepts information that's inaccurate and then goes and develops a theory based on that, and if you'll look at the next -- the last white sheet under this section you'll understand what -- what I'm talking about.

These flowing wells in this area have

pressures on the order of 1000 pounds on the annulus and particularly if they have somewhere around a low gas/oil ratio of wells in the pools. And so what does that mean? That means the flowing bottom hole pressure at the tubing where the oil is coming into the wellbore can be drawn down only to about 1150 pounds.

Now at 1150 pounds, some gas has evolved from solution, but there's a lot left in solution; depending on which of these PVT data curves you choose, there's between 400 and 475 cubic feet per barrel still dissolved in the oil when it comes into the wellbore and comes up the tubing from the bottom of the well.

So that means that there can be a gas/oil ratio no less than 400 to 450 cubic feet a barrel. Anything less than that, there's a mistake. It happened in the field. These oilfields, Mr. Chairman, are operated by humans. We make mistakes and something has happened. I don't know what it is but it's clear to me that there is something wrong. The anomaly that Mr. Hueni places so much emphasis on is erroneous and his conclusions are likewise erroneous.

Q Now, Mr. Greer, I'd like to shift the focus of the case now to the effects of fractures on oil in place and productivity and the validity of interference tests, and in this regard I'd like to now pass out and refer to Benson-Montin-Greer Drilling Corporation Exhibit Number Seven.

Now, Mr. Greer, have you studied the effect of fractures on oil in place and productivity?

A Yes, sir.

Q And are -- is the study a portion of what is identified as Benson-Montin-Greer Exhibit Number Seven?

A Yes, sir.

Q Would you go to the first tab in that exhibit, Tab A, and identify the documents contained behind that tab and briefly review what they show?

A What this shows is the logic behind two different theories of fracturing, which -- and the fractures form the reservoir in this area, and generally most -- most students of this -- of this geological phenomenon have concluded that fracturing often results from folding, flexure of the beds. Whether that's what caused it or not, we cannot be positive and if it is caused by folding, we're not sure that where the folds are now are where the folds were when the fractures were created and so we can't tie exactly in 1986 where the best fracturing might be, but one thing that we do know, of which there's no doubt, no question, no argument, the beds have somehow or other had to be placed in tension. It had to be pulled apart and when they're pulled apart, and caused the voids and the fractures, that's where the reservoir space is.

If they're compressed, and a fracture is pushed together, then there is no reservoir space. So they have had to be put in tension.

Now what I've compared here, and the reason, Mr. Chairman, why I prepared the exhibit which was first presented here twenty years ago, as to how productivity and porosity increase as the width of fractures increase, and the probable relation, since the porosity to pore space varies with the cube root of the permeability, and so --

MR. PADILLA: Mr. Chairman, I'd like to, before the witness starts on this exhibit. I'd like to find out from Mr. Carr how this relates to rebuttal testimony.

MR. STAMETS: Mr. Padilla, I'm going to overrule you because I've given everybody ninety minutes to do whatever they want to do today, or three hours, for whatever they want to do, and it's up to them to determine whether it's relevant or not and we'll allow Mr. Greer to proceed.

Q Okay, Mr. Greer, would you go on now and explain the first exhibit behind Tab A in Exhibit Seven?

A So how I've approached this problem, Mr. Chairman, is I have taken two -- two sections of the reservoir that are folded equally and they have equal fractures, and that's in Plate I and Plate II, and I show the two fractures on the opposite sides of the plate.

Now, in Plates III and IV, if we place additional stress on a formation, stress that's a tension stress, that pulls -- pulls that formation apart, and on Plat III I have shown that the formation is pulled apart until the fractures are increased in width to the extent that we now have 100 times the permeability that you had before, 100 times, and to do that requires about that they be stretched about 4.6 times what they originally were.

On the other hand, and now this is what I think happens. Now, Mr. Hueni, when he was criticizing my -- my approach, said, well, you could just as well have twice as many fractures, twice as much porsity, ten times as much porosity, ten times the porosity, and carried it on to 100 times the fractures, 100 times the porosity. So what Mr. Hueni says what happens is that when we place this additional tension on the formation, is that you don't spread the original fractures, they stay in place, but what happens is you create 100 new fractures, all of the same width as the first fracture.

Mr. Chairman, I'm an engineer. We studied strength of materials, stress and strain, when you place something like a formation like this under stress and it cracks and breaks open, and you place it under further tension, unless there's something to hold this loose block that's in the middle here for it to part and additional fractures create, it's not going to do it. The initial fractures are going to widen. That's just simple logic.

That's my kind of logic; it's not Mr. Hueni's kind of logic.

Q Mr. Greer, go to the next page and review the comparison you've made of porosity and permeability in the area.

A All right. Here we take a direct comparison and in order to understand the significance here, then you put it in perspective, what we're talking about. Now both Mr. Hueni and I have gone from , say, oh, something like 100,000,000 barrel of oil in place in Gavilan. The solution gas drive recovery for that is going to be 5-6,000,000 barrels depending on the detail of what you come up with.

But that's something, what we're looking at for all the wells in Gavilan with a solution gas drive.

Now, that gives you an idea of the total amount of oil that we're looking at, say, from 56 wells.

Here we compare the two different methods, two different logics, and compare what recoveries we might anticipate from comparing two different wells and the two wells that I have chosen are one of our small wells, the C-2, which is shown on the bottom line, had initial productivity of about 56 barrels a day.

Our B-29, if we put big enough casing in it, would have a productivity of about 15,000 barrels a day.

The ratio of the B-29 to the C-2, this is a ratio of the productivity, is about 270.

I say that, you know, just my horseback estimate of how much oil you might expect from -- from the B-29 if you compare it to the C-2, if all other things were equal, and of course they're not equal. One of them is going to drain more area than the other, and such as that, but just for a rough comparison, then this is what my -- my theory would show, about a million and a half barrels, then, would be expected from the B-29.

By direct ratio of the produtivities, the theory that Mr. Hueni propounds, you would have 62,000,000 barrels, completely out of reason.

Q All right, Mr. Greer, go to the next document and identify that.

A The three or the sheets following, the gray sheets, are an article by Mr. Murray, where he investigated fracturing and what the relation of pore space and permeability might be. I didn't -- now Mr. Murray made this study about the same time I made mine. I didn't know about it until years later.

But it's interesting that he comes up with about the same conclusion that I do.

You can see on page -- on the fourth gray page that's entitled page 60 of this article, he goes into a rigorous treatment of how a formation might flex and he even goes so far as to take the radius of the flexure and comes up with a triangular shape fracture and gives it rigorous mathematical treatment, the end result of which is that he comes up with that the porosity is a function of the cube root of the permeability, the same as I do.

Q All right, Mr. Greer, now I'd like to direct you to the information contained behind Tab B, and as you recall, Mr. Hueni discounted interference data on Friday, that had been obtained from an interference test.

Could you briefly initially state what Mr. Hueni's conclusions were?

A Yes, sir. I'll read the first three items here.

It's clear from Mr. Hueni's response that he didn't understand what we were doing in Canada Ojitos Unit because he made three statements.

He said:

1. Interference testing can only show informtion about the formation between the test wells, and

is complicated with fracturing.

2. The EI straight line solution does not apply to a heterogeneous reservoir.

3. The best way to determine the reservoir characteristics is from individual well pressure build up tests.

Q Now are these statements correct?

A No, sir, they're all incorrect.

Q Why were interference tests actually needed out in the Canada Ojitos Unit?

A Well, the very reasons that we needed it was because of the heterogeneous type reservoir. That's why we designed the test in the first place. So, as I indicated, Mr. Hueni just didn't understand.

As to item 2 where he says the EI straight line solution does not apply to heterogeneous reservoir, he's using it, of course, in his analysis in Gavilan. When you use the Horner plot, that's nothing but the EI formula in its most pure form.

I really need to read these last two paragraphs here.

We note that heterogeneity of the formation, whose <u>average</u> characteristics could not be determined from well testing, made need for the interference tests. A reservoir substantially larger thant he drilled area was indicated from some of the pressure testing; and the unit operator required more information about the reservoir so that an orderly and informed development plan could be implemented.

One option was pressure maintenance by gas injection, and a question here was the degree of anticipated gas channeling; the answer to which turned on the level of transmissibility (Kh), not of the "tight blocks" in which the wells were completed, but of the <u>reservoir average</u>.

Interference testing was decided on since it was the only method, then and now, available to determine the necessary characteristics of this fractured reservoir rock.

And I point out here, Mr. Chairman, the example I mentioned earlier in my direct testimony a well that we drilled made 60 barrels a day natural. We sidetracked it 100 feet and made nothing. It would make no difference how you cored or logged those two points 100 feet part; one shows productivity, one shows nothing. There's no way that cores and logs can tell the engineer what he needs to know about this reservoir.

As set out in our direct testimony, the stratified reservoir of the Gavilan presents problems in interference testing, as well as for the individual well pressure build-up surveys, but the Canada Ojitos Unit 1965 and 1968 interference tests were of only one zone and were thus not affected by this complication.

Q Mr. Greer, what response do you have to the assertion that interference testing can only show information between test wells and is complicated by fracturing?

A Well, although most interference tests are just conducted for relatively short times, and they're -- they're necessarily short because of delayed production, the lost income, and also the diffusivity constants are ordinarily low in these reservoirs, and in a sand reservoir, a fairly homogeneous reservoir, you can take a build-up test, determine the Kh, the transmissibility of the formation, then with a short interference test just determine the drawdown and the effect and you can calculate what you need to know, mainly the pore space of the reservoir.

In this reservoir you just can't do that. The individual well tests vary like on an order from 20 to 1, from 200 Darcy feet to 4 or 5, 4 or 5 Darcy feet.

So there is no way that we could average -- average these characteristics and determine what we needed to know.

Now, I'd like to point out how we can determine what we need to determine. Here we have some wells fairly close together, half a mile, a mile apart. We know there's a big reservoir extends beyond it with no wells in it. How do we determine something about the average characteristics of this bigger reservoir?

And we do that by comparing the EI solution, exponential integral solution and, Mr. Chairman, that's a solution to the diffusivity equation, which is based on a point source, just a single point. We use it for wellbores that have a finite diameter but it's relatively small and doesn't check the calculation overall.

When we get to a larger, a larger wellbore, an induced fracture or such as that, then we have to take into account other things.

How do we determine, then, what -- what effect might a large fracture, induced fracture, in your test well, what effect might that have on your interference tests if you used the EI solution, the point source solution?

Well, to determine that we make a comparison and that comparison is that we take two wells, an interference test well, a producing well, an observation well, and I'd like to refer with respect to how this is calculated by going to the blue sheet and look at what happens when a well is put on production in a reservoir, a closed reservoir.

On the upper graph we show that at, for

instance, in two days, that's the first line, the well 2000 feet from the producing well would show a pressure drawdown of about 12 pounds.

One 4000 feet away would be about 5 pounds; 8000 feet away about 1 pound.

After about 15 days the influence of the producing well is clear out to the five mile radius and effects begin to show up out there.

We see down on the lower graph, then, how these lines plot on a semilog graph in order to apply the EI solution to determine the transmissibility, and we see that the well at 2000 feet has a straight line from about one day up to 30 days; for the 4000 foot radius it's a shorter time, about 7 days to 30 days.

But those wells, then in that range, Mr. Chairman, we could use to determine the characteristics we need to know.

Then on the next sheet we see how this all works out.

We show here a reservoir 5 miles in -- 5-1/2 miles in diameter, a shut-in observation well and producing well in the center, and if you have a homogeneous reservoir, no complications, the production and the pressures through the reservoir would be about as shown on the blue sheet.

Now, what if we have complications inside the reservoir between the red dot and the observation well, a large fracture, or whatever, and so to make that comparison, Mr. Chairman, I just assume that we expand the wellbore radius all the way out to that interference test well; just make it no formation. Now Mr. Hueni says interference testing shows only information between the two wells.

So we take an example where we remove the (unclear). There is no formation. It's a wellbore that's 2000 feet in diameter. It has infinitesimal volume but infinite conductivity. And so we make the comparison there. What would happen? What would be the difference, then, in the pressures in this interference test well if we had formation all the way to the observation well or if we had no formation, nothing there, what would the difference be?

Well, we can make that calculation. Muskat has shown us how to do that, and that's shown upon the brown pages. The second -- the first page shows the text; the second page the relation. My pencil notes at the bottom have no significance here; they're just converting to oilfield units. On the third brown page we have the graph and the same data converted to oilfield units.

Then on the pink sheet we show the comparison, the comparison of the EI formula with this larger internal radius, and to see how much error, how much effect there would be, then, if we when we made this test instead of having a formation between a producing well and the interference test well, there was nothing there, nothing, and we find that they're very nearly the same.

It needs to be clear, Mr. Chairman, that I'm not saying that it should pull the pressure down in this large wellbore radius, that this would be the same. What I'm saying is you take the same volume of oil from the well with the entire formation present or you take the volume of oil from a well with no formation present, and this is what you get.

Now, if you make a calculation within one or two days you'll have maybe 100 percent error but you carry it on out to ten or twenty days and you find that your error is only 15, 20, 30 percent at the most, and so what this means, Mr. Chairman, is that the kind of an interference test which we ran in Canada Ojitos, which was designed to determine the characteristics of the formation beyond the distance between the two wells, this is what we would have found. We would have been in error but not very much.

Now, we fraced the producing well, but that was of not consequence. What we have in Canado Ojitos is a system, a high capacity fracture system surrounding tight blocks in which wells are completed. There's probably many a flow down the -- down the channels, down the fractures, but overall, overall a system like a jigsaw puzzle, the channels concentrate toward the producing well, and results in a radial flow solution being a reasonable approach to the calculations of the oil in place.

Q How did this compare to Mr. Hueni's characterization of the reservoir?

A Well, Mr. Hueni says that you can't -- can't calculate it, and, of course, he didn't realize the kind of a test that we made.

The next thing is if it's not a homogeneous reservoir, he says the EI solution won't apply.

Well, whether it's -- whether it will apply or not, Mr. Chairman, depends on whether the tight blocks, the tight parts of the reservoir, whether there is a rate of diffusion fast enough for those tight blocks to make their volumes known to the system as you produce, and we determine that, Mr. Chairman, by -- as shown on the brown graph under Section C.

One of the -- one of the wells that we used, one of the observation wells that we used, had a transmissibility of .02 Darcy feet. We come over to the graph which we've shown before which shows oil in place versus transmissibility, we come up from .02 Darcy feet to the circles and we see there that it has a ratio of permeability to porosity of about 0.4.

Then we go to the next graph, the white graph with the green stripe across it, and we find that for a ratio of permeability to porosity of 0.4 and the saturation situation that existed, compressibility in Canada Ojitos at that time, that we're looking at a diffusivity constant data of about 2 times 10 to the fifth, and then we got to the yellow graph and all this yellow graph is is a solution to the diffusivity constant, to save you having to calculate it, and find the 2 times 10 to the fifth line, which is shown here, the tight block in which this observation well was completed was roughly 40 acres, which would have at best something like 600 feet dimensions. So we come over to 600 feet. At this diffusivity constant we find that it would have equalized in about 0.6 of a day, and so -- not equalized, but we would have -- that would be the time required to reach steady state conditions for it to make -- the oil in the tight block to make itself known to the system.

Now that is depending on a diffusivity constant where the source is in the center and the trenches flow outward.

In this instance we have a block surrounded by the high capacity system that flows the other way; it's much faster, I would estimate, by three or four hours.

So it's just how -- how practical, how true is this?

Well, we found out. We ran an interference test. Within 24 hours the well completed in this tight block had shown the production or the pressure drop which later when we made the calculations for the field as a whole prove out to be true, and that was a mile, it was a mile away from the -- from the producing well.

So there's no question, Mr. Chairman, the interference testing which we did is reasonable. There's no way to get the perfect, exact answer to these reservoirs, but it supports our other information that the porosity of the formation probably varies something like on the order of the cube root of the ratio of productivity to permeability. As such it supports our application, that if we apply that formula to the average production rate of 130 barrels a day in the field, that 200 barrels a day is a reasonable maximum top allowable that this Commission should set.

MR. CARR: Now, Mr. Stamets, we have one additional exhibit but we'd like to take about a five minute break, a short recess.

So far we have used an hour and 22 minutes.

MR. STAMETS: Okay, we'll take a fifteen minute break.

(Thereupon a recess was taken.)

Q Mr. Greer, at this time I direct your attention to Benson-Montin-Greer Drilling Corporation Exhibit Eight, and at this time I will let you testify about the two porosity system and core information.

I would ask you to refer to the document contained behind Exhibit Tab A and identify that, please.

A Yes, sir. I would like to talk about briefly here, Mr. Chairman, that we've had some discussion about there may be a two porosity system here in fractures and perhaps matrix porosity, and so we look at some of the generally accepted theories of fractured reservoirs.

This is -- one of the more recent treatises on this subject is one by Mr. Nelson shown here in the first page.

Following that --

MR. STAMETS: I'm sorry. Is this the --

MR. CARR: Yes, this is the black exhibit, in the black binder.

A Looking now at the second page under Tab A, and we note that in his analysis of naturally fractured reservoirs, he shows fracture spacing running a tenth of a centimeter up to 1000 centimeters. The maximum that he deals with is a spacing of 1000 centimeters, which is approximately 30 feet, and so what we want to do is look at how long it takes for -- for oil in a matrix in a reservoir that's naturally fractured, how long does it take for that oil to make itself known into the fracture system and make its contribution, and so we look here at the 30 foot spacing as being a probably maximum for an ordinarily fractured reservoir.

Then we go to Tab B to see how long it takes for these pressure transients to take place, and we refer here to one of the exhibits which we presented twenty years ago in covering this pool, and if you'll look on the second sheet that has a vertical pink line, we look at a sandstone of 10 millidarcies permeability and we see that it's, in the yellow colored range, that it's ratio of permeability to porosity will run from about .04 to 0.1.

And then on the next page with the vertical green column we find here for that range of ratio of permeability to porosity of .04 to 0.1, and then go up vertically to -- to the compressibility, which would represent the -- probably the slowest rate of diffusion, which would be for saturated oil in the Gavilan area, and we find a diffusivity constant ranging from about 2 to 4 times 10 cubed.

And taking that information we go to the next graph, which is simply a graphical calculation, of course, of the diffusivity constant, and the blue stripe shows where it would be for this particular sand of 10 millidarcies. And we see down at the bottom that for a distance of 30 feet, that's a very bottom line, and the time that it would take for -- to reach steady state conditions in a sand of 10 millidarcies, about a tenth of a day for a 30 feet distance. Now, for this, if the fractures are 30 feet apart, they're really only 15 feet between them, and so it would be much shorter time required to do that.

Now this is for a 10 millidarcy sand, 10 to 20 percent porosity.

Now if you have a one millidarcy sand and one percent porosity, the time is the same. We can tell that by the diffusivity constant shown at the bottom right-hand side, it depends on the ratio, and so the ratio of 10 to 10 is the same as the ratio of one to one.

So if we had a one millidarcy sand and one percent porosity, we'd still be looking at the same blue line.

Now if you have 0.1 of a millidarcy permeability, then it takes ten times as long, and so instead of 0.1 of a day it would be maybe a day and then for .01 of a millidarcy, then that would be 100 times as long, maybe 100 days, or that would be 10 days, 10 days.

So we're really looking at fairly short

times, Mr. Chairman, for the matrix, if there is a matrix, to make itself known if there exists a naturally fractured reservoir, which there's no question the Gavilan is naturally fractured. How close are the fractures? We don't know. Mesa Grande's people in their presentation in viewing fractures which they see by the frac finder logs and wells, have found fractures in every well that they -- that they looked at and there's a six inch diameter piece of the reservoir several miles apart, there's probably quite a few fractures.

It's reasonable to believe that if there's a matrix porosity that it's contributing, it's making itself know to part of the reservoir presssures, and it's not lurking back there to be produced at some future time.

Q Now, Mr. Greer, if there is contribution from the matrix, (not clearly understood) this question, does that change your concern about what's happening to this reservoir at this time?

A No, sir, it's still in trouble.

Q Would you now go to Tab C and identify the documents contained behind that tab?

A I just want to look briefly at some of the pressure build-up tests and drawdown tests and what they show and whether we're dealing with a two porosity system, and one of the better known authors in this regard, or two of them, are Warren and Root. They've shown by the first sheet under the green -- under the blue tab, is the green shaded language says, that "Since the build-up curve associated with this type of porous system is similar to that obtained from a stratified reservoir, an unambiguous interpretation is not possible without additional information."

What that means is, Mr. Chairman, you get a pressure build-up that looks like it might be a two porosity system, it could just as well be a stratified reservoir.

In Gavilan, with the formations being separated as I know them to be, the chances are that it's going be the reflection of a stratified reservoir rather than two porosity system.

Now we go to the next pages which describe some of the methods that are being used to make this evaluation. The white sheet gives an overview of Aguilera by Pollard's method.

Then on the gold colored sheet we see Warren and Root, how their -- their model is shown in the upper lefthand square.

Then on the pink sheet we see a build-up curve from Warren and Root's theory and we note there the straight line where it says omega equals 1, and that -- those numbers there, 1, 0.1, 0.01, 0.001, is the ratio of matrix to -- or fracture to matrix reservoir. If there's all fractures you have a straight line all the way up. If there's matrix contribution, then we have these parallel lines that come in depending upon what percent is what, and that's where the parallel line build-up comes from.

Then Kazemi has a different model. He shows kind of a pancake effect and makes a calculation which he says is better than the Warren and Root's.

And then on the blue colored sheet we come over and we see a comparison of Kasemi's model and Warren and Root's model, and the significant thing here is that they're fairly close together and -- but more important for this particular case, which deals with a low permeability system, they show that the transient effect wipes out in about ten hours and so generally, Mr. Chairman, when we're thinking of a two porosity system and we see it on logs, if it's really there, the matrix is, as we indicated before, is probably contributing and making itself known.

Q Now, if you'd go to Section D, I'd ask you to compare log porosity with that that you can ascertain from core analysis.

A This is the information mentioned in our direct testimony which Mallon received from CORE Lab on their analysis of this curve, in which they feel that the log porosity does not reflect core porosity.

We understand now that Mobil has - has a way of calculating porosity and eliminate these problems, and of course, if so, we are proud of that advancement. I may have to change my way of describing the problem here, that this formation fools just some of the people all of the time and all of the people just some of the time except Mobil it doesn't fool on the core analysis (unclear) the log analysis.

Q Mr. Greer, let's go to Tab E, if you would.

A Tab E is a copy of the core analysis that Mobil provided our engineering committee, or provided one of the members and was given to the engineering committees, and I've referred to that in some calculations that I have following.

Mr. Chairman, the problems that we found with cores in this formation is that conventional core analysis are just not reliable and I know that Mobil's witness, and we're indebted to Mobil for going to the cost and trouble to core the well and get the information and try to help evaluate this reservoir, and Mobil's witnesses say that they used generally accepted industry standards for core analysis, but generally accepted industry standards just doesn't take care of this formation.

We found out the hard way years ago that we've got to do something different.

Here, in order to try to analyze and see really -- really does this low porosity -- we're talking about very low porosity and Mobil's engineer says like we have a 1.9 percent porosity with a cutoff of one percent, and just on the face of it, Mr. Chairman, that's slicing the loaf awfully thin. There just is not much room in there for error and there might be some errord.

What I've done on the yellow colored sheets is just a rough first look at the core analyses and does it seem like it's reasonable, and the way I approached this is I assumed that when this core is taken, ahead of the core head there's some flushing action and it flushes the formation a little bit ahead of it. How much does it flush? Well, we just make a guesstimate, maybe 10 percent, flushes 10 percent. Sometimes that's a reasonable amount.

Now, what happens then? So let's say that it flushed 10 percent of the oil out of the -- out of the pore space. The core then is brought to the surface. As it comes to the surface the oil by solution gas drive expands, drives out the -- first this flush water that came in and then follows it by it's solution gas drive recovery, and in round numbers, if it produces like it should, we ought to have like a 20 percent production to atmospheric pressure.

So we calculate that and we start off by taking the water saturation shown in column four, deduct that from the 100 in column five, we get the initial oil in place, less the flush in column six, less the production in column seven. Then we take column seven and convert it to stock tank barrels by dividing by the formation volume factor, which gives us number eight, and so by subtracting column three from column eight, then we have an idea of -- of how much oil has produced and it should be, we should have zero in that righthand column, if it's the way we figured, 10 percent flush, 20 percent production.

Well, we've got a lot of negative numbers over there. That gives me some concern. Maybe -- maybe we're not flushing the core.

So we make the next calculation on the green sheets and we assume there's no flush. It's zero flush and we take our production, and still we find some negative numbers, and so I'm still concerned.

I go to the white colored sheets and then we assume neither flushing nor production. We just calculate what the production really is and by that we just take the oil that was in place originally and deduct from that what's left, and then in the righthand column we see what was produced, and this is just, Mr. Chairman, it's just like taking a small sample of the reservoir, bringing it to the surface. It's produces what's the recovery factor, and then these blue shaded lines, they're recoveries less than 20 percent. If you're going to get a 20 percent recovery from a sand down in the reservoir, for certain you're going to get 20 percent recovery when you bring it up to the surface, because all the oil certainly had to come out of it.

So we get some pretty small numbers. If they're less than 20 percent I consider them suspect, and there's a lot of blue shaded lines.

If they're more than 40 percent, they're suspect the other way and for instance, let's see, one of the red lines, well, there's 100 percent on sample number 25. It shows 100 percent, the red shading. We look over and it shows the saturation that will bring the core out is is zero and, of course, there we -- something really must be wrong and perhaps the oil was entirely flushed from the core; maybe it was a fracture, and I think maybe that was indicated that way. Maybe all that porosity is fracture porosity.

And I know that Mobil throughout most of threw out most of the fracture -- the core analyses that indicated fractures.

But when you get through with it there's lots of pink lines, lots of blue lines. There's lots of question in my mind, Mr. Chairman, whether there might be something wrong with the coring or with the analyses and I would think that there's a possibility that there's something wrong with the analyses.

So we go to Section G and we plot water saturation versus permeability and it's hard, of course, to tell whether there's any really direction to these lines or not but there are certainly concentrations of the points down around 30 percent porosity and .01 or less millidarcies and we wonder, is this characteristic of sand, sant reservoirs, and for comparison we look at a couple of fairly clean sand reservoirs on the blue sheet, permeability to porosity, and these -- this information, Mr. Chairman, is in the technical literature. It's available to anyone.

The solid lines represent the measured amounts; the dashed lines are extrapolations, and we can see when you get below 0.1 of a millidarcy that the water saturation in most sands increases pretty rapidly.

For the Elk Basin extrapolation it would be up to 100 percent water saturation at 0.1 of a millidarcy.

Then on the pink sheet we compare what we've found from Mobil 4 with this -- these two reservoirs, and we find that it doesn't parallel, it doesn't track the -- the other information, and, Mr. Chairman, ordinarily if we'd had time we would have asked the Mobil people had they done certain things. Had they run analyses to determine the irreducable water saturation? Had they done things that we don't know. They may have a lot of information that we don't know about, but from what we've seen, I have concerns. I have concerns as to whether this is -- really represents what's in the reservoir, and you can see some of my concerns if we look under Section H.

This shows a number of wells that we cored about 15 years ago, had analysed by conventional analyses, and you can see on the first blue sheet how high these porosities run, 5, 6, 7 percent.

On the pink sheet we get the same thing; up as high as 8 or 9 percent, and we go to the yellow sheet and we have the same thing, 7, 8, 9 percent porosity for this shale, and we follow all the way over on the yellow sheets and on the last of the yellow sheets we show some hole core analyses. We were interested -- oh, I'm sorry, it's not the last two, it's the, let's see, one, two, three, four, five, six, the seventh and eighth yellow sheets from the back, and here we have some hole core analyses and we were trying to determine, Mr. Chairman, if there's some way to measure the volume of the tiny fractures, the hairline fractures, the micro-fractures.

So we went to the trouble of doing a hole core analysis and we find the same thing, high, high porosi ties.

The the next following yellow sheets are the core description where we were looking for fractures; how we -- how we tried to identify them.

The last yellow sheets shows where we fraced this particular well. It shows the high porosities, high with respect to Mobil 4, and we treated the well with 200,000 pounds of 20/40 sand, 26,000 pounds of 10/20 sand, 3400 barrels of crude oil. We gave it a fair treatment, a reasonable treatment to test the formation.

This well and the others that were cored here showed capacities after completion and recovery of load oil of like 4 or 5 barrels a day, something entirely noncommercial.

So we knew that something was wrong. With these high porosities we should have gotten something out of them. So we checked back with CORE Lab and we found then, and I don't know just how they are recently, but at that time they assumed that we knew more about the formation than they did, and when we ordered a conventional analysis, we got a conventional analysis, and conventional analysis, where they retort the samples cooks out the kerogen and the water hydration, and so what we were measuring was not the effective hydrocarbon porosity but the sum of the fluids of water and kerogen and such as that, that was in the shale.

Now in the Mobil's core, the conventional anaylses now, they've learned, I guess, that even though most operators know more about it than they do, that they still recommend that they measure the porosity a litte different, so they measure it by what they call the so-called Boyle's Laws method.

And so they get, hopefully, a better porosity and we find then these low porosities that Mobil comes up with, real, real low, 1, 2, 3 percent porosities. They probably are more accurate, but just how accurate there's still a question in my mind, Mr. Chairman.

We see how the saturations don't check. They're still a conventional analysis. They take a sample of the formation and they retort it. They took out the kerogen, the water hydration, along with the -- along with the movable oil, and then they got a problem of how they match all that and come up with the -- with the saturation, so we really don't know whether there is oil in -- in this matrix in this real, low porosity that might actually contribute to production. There's just a real serious doubt in my mind. There's a possibility that it's full of water that this won't move.

In addition that, Mr. Chairman, and I don't know whether this can be accepted as hearsay evidence, we understood a geologist, looking at the core, not having time to -- to cross examine Mobil to ask them about this, all I can do is pass on what I understand, and that is that the core was laminated; that there was like -- 4/5ths of the core was shale, and about 1/5 of it was sand.

Now whether the engineer knew this, whether it's true or not, I can't say definitely, but I have an idea that it probably is true because that's the kind of thing that we found other places.

If so, in the 50 feet of net sand that Mobil's engineer uses might only be 10 feet, and so if it is, it certainly is not going to contribute much to the production, and in addition to that, Mobil's engineer used arithmetic average of permeability. We didn't get a chance to ask him how that compared with the geometric average, but we know that in cases where wells have been tested and compared core analyses permeability with -- with a build-up test permeability, that a geometric average of the permeabilities fits the situation better, and in that instance, then, there is substantially less permeability than -- existing than what the Mobil engineer used.

So I have all these questions in my mind as to whether the matrix, even with Mobil's core, is contributing anything in this area.

Q Were Exhibits Six, Seven, and Eight prepared by you?

A Yes, sir.

MR. CARR: At this time we would offer into evidence Benson-Montin-Greer Exhibits Six, Seven, and Eight.

MR. PADILLA: Mr. Chairman, I would ask that (inaudible) concerning the Mobil core inasmuch as it is purely speculative.

MR. CARR: Mr. Greer has been qualified as an expert witness in petroleum engineering. He advised you of what he was relying on. I think this testimony should be admitted and you can give it whatever weight you feel is appropriate.

MR. STAMETS: Mr. Greer identified it as hearsay and the Commission will take it as hearsay and give it that degree of weight.

MR. LOPEZ: I would also call the Commission's attention to the fact that the Mobil witnesses aren't here and aren't subject to cross examination and Mr. Greer and his counsel have had ample opportunity (unclear.)

MR. CARR: As does Mr. Lopez. If he would like to talk to him about that I'm certain Mr. Greer would do that also, Mr. Chairman.

I have some additional examination of Mr. Greer, with your permission.

MR. STAMETS: (Not heard clearly.)

Q Mr. Greer, what conclusions have you reached about Mr. Hueni's analysis of this reservoir?

A Well, it's been reached through erroneous data, interpretation of anomalies that were not there. His -- his whole case rests on things that were not facts and he's come up with a theory of vertical segregation, gas going up, oil going down, and it doesn't fit what's been found in the field with respect to -- to the stratified nature of this reservoir.

And it just is not that way, Mr. Chairman, it just is not that way.

Q Now, Mr. Greer, Mr. Hueni recommended a certain reduction in the gas/oil ratio. In your opinion will a reduction of the gas/oil ratio alone maximize the potential of increasing ultimate recovery in the Gavilan-Mancos formation from gravity drainage?

A No, sir.

Q If the Oil Conservation Commission should accept Mr. Hueni's reservoir interpretation, and particularly the vertical segregation which he has testified to, what do you believe the Oil Conservation Commission must do if in fact it's to carry out its duties to prevent waste and protect correlative rights?

A Mr. Chairman, if the Commission really believes that this fantastic theory of Mr. Hueni's is credible, that there exists this tremendous vertical communication, then the reservoir has a potential not of solution gas drive recovery, but of gravity drainage recovery, which is some ten times the solution gas drive recovery.

In that instance, Mr. Chairman, the Commission, I feel, to carry out its responsibilities and obligations, would be obliged to require all the operators to seal off the A, B, and C zones in this pool and perforate only the bottom of the reservoir and produce the bottom part in order to achieve this gravity drainage potential.

I realize one of the arguments might be composed of, well, you couldn't get enough productivity if you do that, but all the wells are limited by 50 to 100 perforations in the pipe now where they attempt to get limited entry. They could seal off those perforations, put another 50 or 100 in the bottom and if this tremendous boiling of the reservoir up and down, as Mr. Hueni suggests is really taking place, then this would be the proper action of the Commission to assure the maximum recovery from the reservoir.

Q If Mr. Hueni's proposal is accepted, what effect would that have on waste and correlative rights?

A They would continue; the problems which we identified earlier would continue. Correlative rights, an operator would not have opportunity to protect his correlative rights. The big wells take all the oil.

There would be a loss of the oil which I think is recoverable from gravity drainage, not straight down, but along the dip of the formation, and there would be a number of unnecessary wellsd drilled and resulting waste occur.

Q If the Commission is to act to protect correlative rights and prevent waste, what is your recommendation?

A That they immediately reduce the allowable to 200 barrels a day and place a practical gas/oil ratio limit of 1000 cubic feet a barrel.

Q Do you have anything further to add to your testimony?

A No, sir.

MR. CARR: That concludes my direct examination of Mr. Greer.

I'd like the record to show that we have used 1 hour and 50 minutes of our time.

MR. STAMETS: Thank you, Mr. Carr. I'm going to ask Mr. Greer just two or three questions and then I think we'll move on. I presume you have another witness?

MR. KELLAHIN: Yes, sir, we do.

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Greer, did I understand you to say that you believe that the solution gas oil ratio in the Gavilan-Mancos Pool was 480 cubic feet per barrel?

A Yes, sir.

Q And that's a lower number than I remember hearing any place else in the testimony.

A I believe, Mr. Chairman, it's in McHugh's Exhibit -- let's see if I can find the right one.

Maybe it was Dugan's exhibit, Dugan's Exhibit -- well, McHugh's Exhibit Number Three, under Tab D, the lower line is 480 cubic feet a barrel; the upper line 588, and McHugh recognizes that these are the numbers to be considered.

Q So it is your opinion that the lower number is more accurate?

A Yes, sir.

Q Refresh my memory, what did you testify was the bubble point pressure, really, in this case?

A For Gavilan?

Q Yes.

A I came up with a range, I believe, between 1535 or 40 and 1575 or 80; somewhere in that range.

It's written in one of our exhibits.

MR. STAMETS: We'll excuse Mr. Greer. He'll be available for cross examination later.

Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Chairman.

At this time we would call Mr. John Roe back to the stand and would like the record to reflect that Mr. Roe has been previously qualified as an expert petroleum engineer and he has been sworn and he's still under oath.

JOHN ROE,

being called upon to testify and having been previously sworn, remains under oath and testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Roe, I'd like to direct your attention to the package of exhibits I have passed out in the hearing room and specifically ask you to identify what is offered as Dugan Production Corporation Exhibit Number Three.

Would you identify that for us, please?

A Yes, sir. Exhibit Number Three is a presentation of the current production and/or my estimate of the potential production for every well, all 59 wells that have been drilled and completed and are ready for production in the Gavilan-Mancos Pool area, plus information on one well that's drilling and 13 locations for the nine different operators that are active in the Gavilan-Mancos Pool area.

In addition we've included the data, production data on four Canada Ojitos Unit wells that have been completed and one that is currently in the completion process.

I will point out that the left portion, the 13 columns on this graph, were presented initially in my testimony on August 8th as Dugan Production Exhibit Number One.

Q Is this exhibit identical to Dugan Production Corporation Exhibit Number One with the exception of the additional information on the far right of the exhibit?

A That is correct. The information on the far right was addeds to Dugan Production Corporation Exhibit Number One at the request of the Commission in order to present the effect on individual operators and individual wells that the imposition of a GOR restriction only, leaving the current allowable as is.

Q Mr. Stamets just asked Mr. Greer a question about the solution gas/oil ratio Mr. Greer had used in the Canada Ojitos Unit.

You have testified earlier that the solution gas/oil ratio that you used or determined applied to the Gavilan-Mancos Pool was the 588 cubic feet of gas to 1 barrel of oil.

Would you explain to us why you have utilized the 588 number as a solution gas/oil ratio?

A Yes, sir. I am aware of Mr. Greer's PVT data and up until PVT data was available from well in the Gavilan-Mancos Pool, which is McHugh's Loddy No. 1, we were using PVT data that was available from the Canado Ojitos Unit.

Basically, as a result of our study group, engineering study group subcommittee studying this pool, we have agreed that it probably would be more appropriate to utilize PVT data from a well in the Gavilan-Mancos Pool area if we had confidence in that data and I personally have confidence in the data that we obtained in the fluid sample from the Loddy No. 1, which is where the 588 comes from.

Q You heard the testimony on Friday, Mr. Roe, by Mr. Pomeroy with regards to his tabulation and his comments with regards to the apparent effect the various suggested restrictions would have on various interest owners.

Do you have an opinion, Mr. Roe, as to whether your presentation, Exhibit Number Three, is a more accurate and reliable presentation of the effect on the operators of the various proposed reductions in producing and gas/oil ratio (unclear)?

A Yes, I have an opinion.

Q What is that opinion?

A I believe that upon reviewing Koch's Exhibits Number Four and Five that there's a good chance that there is an impression given that Dugan Production and Jerome P. McHugh have some hidden benefits in asking the Commission to restrict the gas/oil ratio and oil production rate.

On Koch's exhibit it indicates that McHugh and Dugan both recognize the largest percentage increases after allowables are restricted as proposed.

There -- there are some misleading calculations there. It's my feeling that the real impact upon individual wells or individual operators is more properly presented in my Exhibit One initially, as revised and presented in Dugan Production Exhibit Three.

The main problem that I see in Koch's presentation was that by comparing April to June and then contrasting the percentage change between April and June's production for each operator, and then also contrasting the reduced production rates with April's rate, if you're unaware that during this April to June time framed operators were putting additional wells on production, which is the case for Dugan Production and McHugh, plus two other operators, Mobil and Mesa Grande, the actual oil, increase in oil production that occurred between April and June, appears as a positive benefit that could easily be misunderstood that this is simply a positive thing that resulted because of our proposed application.

For instance, Dugan Production rates during April of 1986 averaged 25 barrels of oil per day. This was from two wells that we were operating. During May we placed the Tapacitos 4 on production and during June our production from the Tapacitos 4 alone averaged 153 barrels a day.

Our company production during June was 188 barrels a day, and so a large part of the 430 percent that was shown as a change in production is simply because Dugan put one well on; McHugh put ten wells on production during this period of time. Also not reflected on Koch's exhibit was the fact that Mobil put all three of their wells on production between April and May, resulting in a production during June of 388 barrels of oil per day for them, which basically is an infinite increase if we use this same line of thinking.

Mesa Grande putting their four wells on production during this time periodd resulted in an increase in production from them from a daily average in April of 399 barrels a day to an average of 725 barrels a day in June.

Now the numbers that I just quoted are different from what was presented on Koch's numbers. Koch basically reflected a very small increase in production for Mesa Grande between April and June.

Q Mr. Roe, let's turn to page four of Exhibit Number Three and if you'll look at the middle of the tabulation where it says total Gavilan Pool area, and as you read from left to right, if you'll find that portion of the exhibit that refers to the June '86 production, the reservoir barrels of voidage a day, the 26,000 barrel number, and then go over and look at the proposed allowable reduction under the McHugh proposal of approximately 14,000 reservoir barrels a day, and then finally, under the sensitivity case that was used in Mesa Grande's proposal of only the solution gas/oil ratio, the 21.5 number.

Having directed your attention to that portion of the exhibit, Mr. Roe, can you explain to us what the significance is of the tabulation in terms of what you're trying to accomplish with the proposed reduction in the producing rate to 200 barrels a day and the gas/oil ratio down to 1000-to-1?

A Yes, sir. As we've indicated there, and I might just clarify now what I show under June '86 production and/or potential reflects actual production based upon June's production as reported to the Commission and for wells that had -- had no production during June but were completed and ready to produce, which we have approximately 16 of those wells, I have estimated, based upon production test data that's available, or maybe a well produced -- did not produce in June for some other reason; it was maybe shut-in for lack of a gas market or problems with their gas contract, but the 8188 barrels that I show as being June's production, it's comprised of 2117 barrels of estimated production from wells that we really have shut-in and to date we have not seen the production, the impact upon the reservoir from production from those wells.

It also includes 6071 barrels, which is an actual per producing day average from wells that did produce in June.

Q What's the rationale behind the proposed McHugh reduction in producing rate and gas/oil ratio?

A The -- what we were trying to obtain is recognizing the fact that during June we have right now wells completed that could cause a reservoir voidage of approximately 26,000 barrels a day. We recognize -- and that voidage is causing a rate of pressure decline in the reservoir that is -- that we're uncomfortable with. We feel a need to study the reservoir to be sure there is not a different method to develop and produce the reservoir than we're currently operating under. Right now we think there's a good chance there is.

So recognizing that we currently have potential for 26,000 barrels a day, we're unhappy with the rate of pressure decline. We feel that the rate of pressure decline needs to be slowed down to some lower rate, and we have chosen an oil rate and gas/oil ratio that is -- we feel to be practical considering that the reservoir has been on production, the gas/oil ratio has increased. Our intentions were to buy some time with the reduction but still maintain a production level that hopefully wouldn't cause undue economic hardship on operators in the pool.

Q If the Commission adopts Mr. McHugh's proposal and reduces reservoir voidage to 14,000 barrels a day, what period of production time does that relate to or correspond to?

A This is a production level that existed in March and April of this year, which is about the time we started formulating our plans and trying to get something moving with regards to studying the reservoir.

Q Let me direct your attention now, Mr. Roe, to Dugan Production Corporation Exhibit Number Four, which is the colored bar graph following the last exhibit.

Before we discuss your interpretation of the exhibit, would you take a moment and orient us as to how the exhibit is prepared and what you're attempting to depict?

A Yes, sir. The purpose of making this exhibit, and this exhibit consists of five pages, the first page is really the only page we'll talk about, the information presented on the last four pages is simply the tabular data that supports each individual sensitivity case that we considered. It's presented in the same manner by well by operator as was the Exhibit Three that we just discussed.

For ease in comparison of one case versus another case, we've presented the top page of Exhibit Four. We've identified each case that we're -- we have presented at the bottom. For instance, the leftmost case, which I've got a red arrow under, that is what we showed to be June '86 actual and/or potential production. It was presented on Exhibit One and again on Exhibit Number Three.

I've chosen the four largest companies which would be McHugh, Mesa Grande, Mallon Oil, and Meridian, and I've identified those in color code, yellow, orange, green, and blue, and I've been consistent across the graph. So the comparison of each operator's share of the production under any one scenario is -- is hopefully a little easier as far as just a visual comparison.

Q On the graph on the far left there are some horizontal red lines approximately 9000 and then it continues up and there's two more lines, what's the significance of those lines?

A Okay. Those -- those are the approximate reservoir voidages that existed in January, as Mr. Kellahin said, that the first, the bottom line is 9306 reservoir barrels a day. Now this reflects the actual, not any potential, this is the actual pool production that did occur during January '86, and it corresponds, I've indicated on the righthand portion of the -- of Exhibit Four, it corresponds to a daily rate of 4234 stock tank barrels a day and 4435 MCF a day and this did come from 34 wells.

The next line up is the production voidage, which is approximately 11016 reservoir barrels per day, that did occur during May of 1986.

The uppermost line is the approximate reservoir voidage that actually occurred during June of 1986 and that volume was approximately 17,163 reservoir barrels per day.

So by having the three lines across the page, you get an idea of where each case would relate to the reservoir voidage during January, May, and -- or January, May, and June.

Q If we go to the far right side of the tabulation, the bar graph, and look at the sensitivity test that's based simply on reducing the gas/oil ratio down to 588, in your opinion, Mr. Roe, is that a significant enough decrease in reservoir voidage?

A No, sir, it does not provide the level of voidage that we feel necessary in order to slow the rate of pressure decline. It basically gives us a rate of pressure -- or rate of voidage that is not grossly different. In other words, the total reservoir voidage under that scenario would be a bout 23,700 reservoir barrels per day, which compares to the current potential of 29,000 and a desired level of about somewhere between 11 and 14,000 barrels per day.

Q Do you have an opinion as to whether or not we are being as effective with preserving the reservoir energy if we only reduce the gas/oil ratio to the 588 number as opposed to the proposed McHugh solution?

A Yes. I have an opinion and I feel that if we do not also make an adjustment on the oil rate, as I've indicated with the visual presentation on Exhibit Four or the actual tabular information on Exhibit Three, if we restrict only the gas/oil ratio to 588 and leave the oil at 702, we will still have a reservoir voidage potential of about 24,000 barrels a day.

McHugh's proposal would put the reservoir voidage at a range of about 15,000 reservoir barrels per day.

And again, now, that is going to put us back at a level that we're still not happy with. The reservoir pressure is declining at a rate that's still pretty -- pretty fast, and we don't have a whole lot of time even at that level of reservoir voidage to arrive at a conclusion as should we be doing something different to the reservoir.

Q Let's turn, Mr. Roe, to Exhibit Number Five and have you identify the three pages that compose Exhibit Number Five.

A Okay. Exhibit Number Five, as Mr. Kellahin said, consists of three pages. These are nothing more than a reproduction of a production graph that we keep monthly, plotting monthly production data for Jerome P. McHugh's ET No. 1 on page one; the Janet 2 on page number two; and the Native Son No. 2 on page three.

Q Mr. Hueni, in his testimony last week advised us that he had not utilized production data after the May '86 production information.

In your opinion is there significant production occurring in June and July that would affect the formulation of opinions about the gas/oil ratio?

A Yes, sir. As I indicated on these plots, and I have chosen wells that we are really concerned with, we are starting to see dramatic increases in gas/oil ratio and corresponding decreases in oil rate. A bulk of this is just within the last few months.

Q Would you take one of these as an example and show us what is occurring since May's production?

A Okay. For instance, in the first page of this -- this exhibit would be the ET No. 1. I -- even during May the gas/oil ratio in this particular well was -- was exhibiting an increase that we were not real certain of. That increase became more obvious in June and July and even so far in August it's actually increasing.

Using ET-1 as an example, say, during February our gas/oil ratio was 439 standard cubic feet per barrel.

During July the gas/oil ratio has increased to 6492 standard cubic feet per barrel, and we've had a corresponding drop in oil production from 236 barrels a day at its peak level, which I might add was substantially higher rate than we had obtained from the well before, and I personally feel that this higher rate we observed was primarily a result of us approaching a bubble point in this well, additional free gas becoming available, the well flowing, it probably had the potential for this all along; it's just with the production equipment we had, we just were not seeing the potential until it began to flow with additional gas.

As we approach the bubble point the well began to flow, production increased from 900 to 1000 barrels a month, to 5-or-6000 barrels a month, and that production rate is dropping off as the gas/oil ratio is -- is really going out of sight.

I haven't plotted August data on here but during the first 18 -- first 15 days in August the gas/oil ratio has averaged 10,470 -- 52. It's actually going up every day.

Q Mr. Roe, Mr. Pomeroy testified on Friday and I think he related to his Exhibit Number Ten in his conclusion and said that the McHugh's proposed cut would save only a meaningless few pounds of pressure.

Do you agree with that conclusion?

A No, sir, I do not. Referring back to Koch's Exhibit Number Six, it's my understanding that from Exhibit Six, that meaningless few pounds -- at least Exhibit Six covered a 7-month interval. He was talking about 100 pounds of pressure.

In order to make that forecast it's my understanding that a constant rate of production that existed in June was utilized, and it's also my understanding that -- well, basically a constant rate of production and a rate of pressure decline that was already established in

June, which utilized the forecast in the future.

Q Mr. Pomeroy forecasted over a 7-month period a loss of 100 pounds of pressure, I believe?

A Yes, sir.

Q What in your opinion would be the estimated loss of pressure over the same interval?

A It -- if we make no effort to restrict reservoir voidages that are increasing, it's my opinion that the rate of pressure decline will increase to a level that I have not been able or I cannot calculate, but I would estimate that it would be at lest 150 to 300 pounds of pressure loss during the same 7-month period.

Q In your opinion, Mr. Roe, as a petroleum engineer, is that a meaningless few pounds loss of pressure?

A It is not.

Q What action, Mr. Roe, can the Oil Conservation Commission take to give the working interest owners an opportunity to produce more oil from this reservoir?

A Well, it's my opinion that the Commission must take some action to immediately reduce the rate of reservoir withdrawal, the reservoir voidage, and the reason that this is necessary is to give the operators of the Gavilan-Mancos Pool, buy them some time that they won't have at the existing rates of pressure decline, to evaluate in a more complete manner what should be done with regards to future development of the reservoir and future production operations of the reservoir.

Since conducting our pressure tests or our interference tests in December of '85, we, we being McHugh and Dugan, primarily, but I think probably most of the other operators are -- that are aware of the pressure data are also concerned, that there is a urgent need to arrive at a conclusion as to is there a better way to produce the reservoir and is there a better way to further develop the reservoirs.

It's my feeling that to date we have established in my mind undoubtedly that pressure communication, good pressure communication, exists well to well on a current development pattern.

It also exists throughout the reservoir. I feel this is supported in Dugan Production's Exhibit Number Two presented on August 8th.

In addition to that, I feel that on the existing spacing of 320 acres per well there will be unnecessary wells drilled on a competitive basis. These wells will be required, in order to develop undeveloped acreage, prevent lease expirations, protect correlative rights, and prevent drainage. This also was presented in some detail in Dugan Production's Exhibit Number Two.

I feel that we have information and have enough data to feel gravity drainage potential, or there is potential to recognize some gravity drainage in the Gavilan-Mancos area, and gravity drainage is occurring.

We also, it is my believe, that by allowing continued competitive operations of the reservoir there will be an effort, or there will be waste of natural reservoir energy in the production of higher gas/oil ratio wells, in their efforts to compete for their share of the oil, daily oil production.

MR. KELLAHIN: That concludes my examination of Mr. Roe.

We move the introduction of Exhibits Three, Four, and Five.

MR. STAMETS: Without objection these exhibits will be admitted.

I've got just a couple of questions of Mr. Roe, and then we will see what everybody else wants to do.

MR. KELLAHIN: Mr. Chairman, my timekeeper here tells me we've used 2 hours and 18 minutes and we'd like to reserve the balance which we believe is, what, 42 minutes, 42 minutes for a later time.

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Roe, there was some discussion about -- a lot of discussion about how this would affect individual operators and they will, some operators would be losing current allowable in production.

Would it be possible at some time ninety days from now to go through there and calculate again how much each operator has lost or gained in comparison to the others between the allowables as they would have been and the allowables as calculated under your proposal, and then to restore balance should that prove to be the correct thing to do?

A The way you asked the question I'd have to answer yes, that's possible.

Q Thank you. The second question is one that I asked a number of folks on the other side last week and they all answered in the negative and I kept thinking I was asking the question wrong.

In this solution gas drive reservoir, if we allow wells to produce at GOR's above the solution gas-oil ratio, you say it's 588, if we allow wells to produce at 1000 or 2000, are we pooping off our reservoir energy and not making the best use of it in producing the oil out of reservoir?

A If I could just clarify a little bit, if solution gas drive is the only mechanism that's in effect, I think possibly the answers you got earlier would be the same as mine, is the rate that you allow the pressure to decline and the gas to evolve is probably not going to substantially affect ultimate recoveries from the reservoir.

But what we have here and why it's important and maybe why you're expecting a different answer, and why I'll give you a different answer, is I don't feel solution gas drive is the only mechanism that exists.

I do feel solution gas drive is going to be important if Mr. Hueni is right, and we have a reservoir 600 feet thick, which I don't agree with, but if we do, we will have some of that gas that evolves from solution go to the top of the structure that's 600 feet thick and basically act as a gas cap.

You have these wells that are completed in this gas cap or completed close enough to the gas cap that then will start producing gas out of the gas cap and that's where the reservoir waste is going to occur, is rather than that gas being trapped in the gas cap and serving to displace oil downward, as Mr. Greer said, in order to take advantage of that, we've got to go in and squeeze off all of our upper perfs and let this gas cap drive the oil down to the bottom of the pool.

If we don't force that mechanism to operate in the reservoir, then there will be reservoir energy wasted by anybody that's producing gas out of the gas cap, whether that gas cap exists at the top of the 600 foot reservoir or at the top of the reservoir that we're referrng to as the Gavilan Dome.

And that's one of our primary concerns right now, is an operator that's got a high gas/oil ratio, if he has the only restriction of 1.4-million a day or 700 barrels of oil a day, he can produce up to 1.4-million trying to get more oil and using McHugh's ET as an example, the gas/oil ratio right now is 10,000-to-1.

We're going to be able to produce a lot more gas trying to get our share of the oil out of that well than -- than really is going to be effective for the reservoir, and again, that's -- my statement of that is because I feel some of that gas is probably going to be more than just the solution gas drive process working. It's also producing some gas from a free gas phase in the reservoir.

Q Under those conditions you would be using more than your fair share of reservoir energy.

A Yes, sir.

Q All right.

MR. STAMETS: We'll excuse this

witness and move on, then, to the cons, the opponents over here, and what is your pleasure at this point?

Who's first?

MR. LOPEZ: Mr. Chairman, let me ask you then a couple things off the record.

(Thereupon a discussion was had off the record.)

MR. LOPEZ: On behalf of Mallon and Mesa Grande, I would at this time, Mr. Chairman, request we be given for procedural, substantive due process reasons, the same opportunity to prepare surrebuttal to the testimony we heard today.

The testimony we heard this morning from Mr. Greer and Mr. Roe goes far beyond anything contemplated as rebuttal. It was new evidence, new testimony with respect to matters occuring thirty years ago, and I would think that it would be only fair and equitable that we be given the same time frame in which to prepare our case with our books of exhibits, if necessary, to rebut what we've heard this morning and at least the four days that they were given since the hearing was recessed last Friday.

MR. CARR: Mr. Stamets, I would submit that every bit of Mr. Greer's evidence was locked in and in response to testimony that was presented by the cons, if you want to call them that; that it was properly rebuttal testimony and if they were not anticipating that, they should have been when Mr. Kellahin advised the Commission and everyone in the room that we would call Mr. Greer for rebuttal testimony this morning.

We believe that there is no unfair advantage in going ahead and wrapping this up.

We found out yesterday that we had about four or five hours worth of testimony that we had to reduce, hopefully, into ninety minutes. We didn't make that, but we came close.

And perhaps you want to break for lunch now and give them an opportunity to respond, and we would like to conclude this hearing today.

MR. PADILLA: Mr. Chairman, earlier I objected for the same reason, especially when Exhibits Number Seven and Eight were -- at least Exhibit Seven was being presented by Mr. Greer.

In looking at Exhibits Seven and Eight, most of that information is entirely new evidence. The question on (unclear) and the questions on reservoir materials presented by Mr. Greer this morning are entirely different.

On Friday Koch reviewed our testimony, engineering testimony that was going to be presented through Mr. Bennett. We thought at that time that that might be cumulative evidence and it might not be necessary in light of the Commission's admonition of shortening the hearing.

Part of what we were going to introduce through Mr. Bennett involved reservoir studies of fractured formations and anticipating whether or not Mr. Bennett, who also had a conflict today, and in deciding whether or not we should put on -- we needed him today here, we anticipated that we would be looking at some type of rebuttal and the scope of the testimony would be on rebuttal.

We do not have that type of case and it's evident that we've been somehow set up in trying to -- trying to view Mr. Greer's testimony today.

So I would concur and I would join Mr. Lopez' motion.

MR. STAMETS: The Commission is going to not continue this case. We are going to allow it to go to conclusion today.

Each side was aware of that when we concluded last week.

I don't think that the testimony that we've heard today is new, startling, or unavailable to anybody, and at best, we would take a recess till 1:00 o'clock if that's everybody's choice, and allow you to organize the data that you have, and certainly we did not suggest that you leave any of your experts at home for today.

MR. PADILLA: Well, if I may respond to that, Mr. Chairman.

Normally we follow, and I believe the rules of the Commission state that the rules of civil procedure will be followed (not understood) on trial to a court. In that event, normally, the rules and the scope of testimony are limited to what has been previously testified to whether it's rebuttal or surrebuttal (not clearly understood).

MR. KELLAHIN: Mr. Examiner, point of clarrification. The New Mexico Rules of Civil Procedure do not concur with Mr. Padilla's analysis of those rules. You are not limited to rebut only that information that is presented on direct, and they are not so construed.

MR. PADILLA: Well, you're certainly not allowed to introduce or bring in entirely new testimony on rebuttal.

MR. STAMETS: The Commission does not believe that we heard anything new this morning.

We believe we heard simply a massaging (sic) of information which had been presented in one form or another in this case at an earlier date.

Also, I believe that -- that it says we are going to follow those rules generally but not exactly, and this is going to have to be one of those times when we follow them generally. I don't consider any of the participants here without resources or disarmed or without experts of high caliber who are capable of going on with this hearing today.

And since the time is as it is, we're going to recess till 1:00 o'clock and allow those --

(Thereupon the noon recess was taken.)

MR. STAMETS: The hearing will please come to order.

Where is Mr. Lopez?

MR. PADILLA: I would like to cross examine Mr. Roe at this time.

MR. STAMETS: Very good.

CROSS EXAMINATION

BY MR. PADILLA:

Q Mr. Roe, let me direct your attention to a few things you testified about this morning.

It's my understanding that -- that based upon the schedule that you have on page number one, Dugan has approximately eight wells in the Gavilan-Mancos Pool, is that correct?

A I have listed four wells that we -- are actual wells, and four additional wells that are planned; they are locations for planned wells.

Q In other words, only the ones with the figures on columns -- well, I'll just column, the first column on cumulative production is the only wells that show any production there are the ones that are producing, is that correct?

A Yes, sir.

Q Let's go now to the June 6th, 1986, production, and let me ask you to identify for the Dugan Production the June production was 228 barrels a day, is that correct?

A Yes, sir. I have indicated that during the month of June Dugan could have produced 228 barrels. Of that 228 you'll notice that 40 of it has subscript E, which means we don't have a pipeline connection for that well and if we could get permission to vent the gas, it's my best estimate it would produce 40, but what we actually produced was 188 barrels of oil per day, and that is an actual number.

Q Going across the exhibit, then with the proposed allowable, you still have a figure of 228 barrels, is that correct?

A Yes, sir.

Q So you show no reduction of allowable (inaudible to the reporter.)

A That is correct.

Q And the same applies with respect to the last column.

A Yes, sir.

Q Let's go on down to the Mallon group of wells and you show for June an average daily production of 1811 barrels a day, is that right?

A Yes, sir.

Q Under your proposal they would have a reduction of 772 barrels or a reduction to 772 barrels.

A Yes, sir.

Q Approximately how much of a reduction is that?

A Okay, under the existing, actual conditions, June '86, the number right below the 1811 indicates that Mallon Oil has 19-1/2 percent of the production or potential that would -- could exist during June.

Q Now, Mr. Roe, this is not based on the number of proration units that Mallon operates, correct?

A I'm sorry.

Q In other words, there's no acreage factor in this computation.

A No, sir, it's strictly based on barrels of oil per day.

Q Okay. Now, let me go back to my previous question. What's the approximate reduction -- or let me ask you this question instead.

Would you agree that the reduction from 1,811 to 772 would be greater than 50 percent?

A Yes, sir.

Q Now let's go on to the next page and I'd like to ask you some questions with regard to the McHugh wells.

In looking at the McHugh wells would you agree with me that only, possibly only one well of all the wells listed in that is capable of producing like the first three Mallon wells on the first page?

A Only one well?

Q Yes, the one that's right in the middle of the page. The one that produces 619 and another, the Native Son No. 2 produces 440.

A I think we need to clarify one thing just a little. Basically most of McHugh's wells are producing against pipeline pressure, which is averaging around 250 pounds.

If we had our wells, a lot of which are

flowing, producing into a gathering system which has a lower operating pressure, such as Mallon's wells, our wells might be a little higher during June than they are. They're later in their productive life and McHugh has had higher productivity from his wells. But basically, under existing pipeline conditions your assessment is correct; there is only one well that's capable of producing higher rates at --

Q Would reducing the GOR reduce the pipeline pressure?

A No.

Q You're producing directly into the pipeline, is that correct?

A Yes.

Q No gathering system whatsoever?

A Well, that's not true. Mr. McHugh has installed several gathering systems in order to deliver gas. That is -- that is correct, but he has not installed compression or processing facilities such as Mallon has.

Q In other words, what you're telling me is that if you reduce the oil allowable there is a possibility that most of these McHugh wells would run up to 200 barrels a day.

A I think I have some numbers on -- on my tabulation that would basically reflect what you're trying to get at. For instance, during the month of June '86

McHugh's wells represented 39.7 percent of the total pool production. That is the number that lies right below the daily average production during June.

Under McHugh's proposed application his -- rather than 39.7 percent of the total production, McHugh would only produce 37.5 percent of the total production, so in fact his total production with respect to the total would actually be decreased and that was basically my comments with respect to Koch's exhibits, is -- is McHugh would experience actual reduction in percent of the total pool.

Now any operator that basically has small volume wells isn't going to be affected as much as the operators with larger volume wells, and that is correct.

Q Well, let's look at your subtotal line on the bottom of page two. The deduction as you have calculated it for June 1986 production of 36 -- 2,686 to your proposal of 2,035 is a reduction that's over 50 percent, correct?

In other words, you're not going to be cut as drastically as Mallon wells would be cut.

A That is correct. Mallon Oil will, if you look at the percentages underneath Mallon's production, he will share or carry a larger burden, in other words, existing he has 19-1/2 percent of the total pool. Under the existing proposal of McHugh's application, he would have 14.2 percent of the total pool. So he would take a greater percentage but he -- his wells are causing a big part of the problem that we're concerned with. A lot of my pressure data did indicate that we are -- his wells are likely draining more than 320 acres.

And that was the big part of my presentation in Exhibit Number Two.

Q And you've also shown here that McHugh has 28 wells, is that correct?

A Again, there's 28 entries on this tabulation. There's actually only 23 completions and 5 locations.

Q Of these wells listed here you already have a cumulative production of 1.3-million barrels of oil, isn't --

A Yes, sir.

Q -- that also correct?

A Yes, sir.

Q A little greater than 1.3-million.

A Yes, sir. We've been producing those wells since early -- or the latter part of 1983, also.

Q So let me see if I understand this correctly. We have -- Mallon is going to suffer the larger reduction. McHugh has already produced a considerable amount of oil from the pool and now you're asking Mallon in your proposal to have further reduction, a disproportionate reduction, isn't that true, in a nutshell?

A Well, that's -- from the standpoint of just cranking through the numbers, that's the way it is, yes, but part of my testimony was that the allowable of 702 barrels a day allows the wells capable of producing that much of draining areas that exceed the 320-acre unit that they have allocated to them, and I feel we've substantiated that fairly -- fairly conclusively with pressure measurements between Mallon's wells and Dugan Production's wells or Mallon's and Canada Ojitos wells.

Q Well, would you agree with me that the number of wells out in the field is in direct proportion to the spacing?

A I'm sorry, the number of wells is --

Q The number of wells out in the Gavilan-Mancos Pool is directly proportional as far as the spacing rules.

A Yes.

Q For every well there's a 320-acre proration unit.

A Yes, sir, I'd agree with that.

Q And that's -- those are the rules that --

A Well, that's not true. There is one spacing unit that has two wells in it, which is operated by Mr. --

Q Possibly with an exception, valid exception.

A Yes. There is one authorized exception, yes, sir.

Q If we go on an acreage basis, just from looking at your Exhibit Number Three, Dugan has eight proration units out there. He doesn't have a whole lot of production.

Mallon has six wells and they have quite a bit of production.

And McHugh -- well, three of those wells, Mallon wells, have quite a bit of production, but on an acreage basis McHugh as a disproportionate number of proration units, isn't that correct?

A McHugh has a larger acreage position in this area and he has been more expeditious in developing his acreage, that is correct.

Now, I might add, you know, Dugan Production has we -- it's true, we only operate four wells but we do have an interest in 38 wells that exist in the pool.

Dugan Production's acreage position is about the third largest in the pool, which brings back Meridian's witness testified to the real way to analyze this in the impact upon individual companies would be from a net interest basis. That would be a much more tedious calculation and we did not -- the true impact upon each operator is not --

Q It's not reflected in your exhibits, is that correct?

A That is correct. In other words, you have to look at the net interest in each well and I was not prepared to make that calculation.

Q Let me quickly have you refer to your Exhibit Number Four and ask you, sir, to -- do you agree with me that this exhibit does not show an acreage factor in it?

A I'm not sure I understand what you mean, an acreage factor.

Q Well, looking at Exhibit Number Three, McHugh has at least 28 proration units out there and if I look at the little, yellow rectangles here, that -- there's no acreage computation or factor in that --

A In other words, what's presented there is basically the wells operated by Mr. McHugh, that's correct.

In other words, I have not made an effort to account for only McHugh's ownership in the total pool, as I haven't in Dugan's or any others.

What I've presented here would be basically the wells operated by each operator.

MR. PADILLA: I believe that's all I have, Mr. Examiner -- Mr. Chairman.

MR. STAMETS: Next? The witness may be excused.

GREGORY B. HUENI,

being called as a witness and having been previously sworn and remaining under oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. LOPEZ:

Q The record will show that you're still under oath and that you're the same Mr. Hueni that testified previously in these hearings.

Have you had an opportunity to review the testimony and evidence presented by Mr. Greer this morning in this hearing?

A Yes, I have.

Q Over the lunch hour?

A Yes, I have.

Q And if so, I would like you to comment on this, please.

A Yes, we have reviewed the information presented in Mr. Greer's exhibits.

What I'd like to do is I'd like to look at the various exhibits he presented and comment with respect to those individually.

Before we would look at the first one, I'd like to make a general statement that gas cap expansion is not a bizarre phenomenon that happens in reservoirs; that it is something that's been observed worldwide and, in fact, it's the same equivalent, or more or less equivalent to the gravity drainage that Mr. Roe discussed in his testimony, as well.

So it's not -- it's not a bizarre phenomenon and it is one which we still believe is one of the principal mechanisms for production in this particular field.

If possible, I would like to refer now to the BMG exhibit with the yellow cover on it and I'd like to try and comment on the various exhibits within this overall exhibit that are perhaps pertinent.

The first plot following the title of the exhibit is a blue sheet which was taken from our report, which shows oil production and it shows gas/oil ratio, and it has circled in the period 1985-1986 the gas/oil ratio information and it is designated as -- or a handwritten note saying that this is wrong.

The data that we have presented includes two wells that Greer elected to exclude. That was the Gavilan Howard No. 1 and the Gavilan No. 1. Both of those wells are wells in which we unfortunately don't know the exact amount of gas being derived from the Mancos formation as opposed to the Dakota formation. It is perhaps not completely correct to characterize this as wrong. It's simply there is a certain amount of gas production that is attributable to, perhaps, the Dakota in those two wells that should not be included in the Mancos, but unfortunately nobody really knows what the volume of that -- that gas production is. So, we have included those two wells in this plot. We mentioned in our direct testimony that we recognize the difficulty of doing that and subsequently we had referred to the gas/oil ratio information presented by Mr. Roe, which excludes the Gavilan No. 1 and the Gavilan Howard.

That gas/oil ratio information was presented as a plot of pressure and gas/oil ratio versus pool total cumulative oil production. It showed pressure trends for individual wells. It showed the producing gas/oil ratio from 1984 through, I believe, June of 1986. It showed what they interpreted to be the PVT data, indicated solution GOR.

They had two lines on that, a 588 and a 489 line. This is one of the exhibits in -- in the yellow notebook, is this particular plot.

We would like to note with respect to that plot that once again, that a pool total cumulative oil production of 200,000 barrels, a gas/oil ratio goes to a value greater than the solution gas/oil ratio. We've had --

we've heard the argument that the bubble point pressure is a value lower than the one we used in our analysis. Our analysis was based on a bubble point pressure of 1770, which pressure was reached about the same time that the solution GOR went greater than the PVT data indicated GOR.

We realize the difficulties in obtaining good fluid samples and representative fluid samples, and we don't underestimate those -- those difficulties, but we believe that the fluid sample data has to be in agreement with field producing conditions and this is actual producing conditions that have indicated that we have production of free gas from the reservoir, and that can only occur if we drop below the bubble point pressure over a large area of the reservoir.

So we have used as an indication that the bubble point pressure is higher the actual field producing GOR behavior, as shown on that particular plot.

I'd like to move to the next page back, which is a pink sheet. It is a Horner solution gas drive analysis run for the -- the Gavilan Mancos Pool. We have once again curves showing predicted GOR and actual GOR, actual pressure and predicted pressure, and we have on that particular exhibit, we have our predicted GOR -- well, we have the notes that -- that Mr. Greer has penciled in; our predicted GOR being 3100, the Greer predicted GOR being 2200.

It was his contention that that was not a result of the difference in fluid properties but more a difference in the rock properties, as well as, perhaps, some incorrect calculation of solution gas drive performance.

I'm not sure how to respond to that, that type of criticism, other than the fact that we have used this program in several studies. We've hand-checked it. We've checked it against published literature data, and it has been consistently valid in all cases and we see no reason why it should experience some sort of problem in this particular calculation.

We would note that regardless of whether we would take our curve, where we predict a GOR of 3100 or Greer's curve, where we predict a GOR of 2200, both of those are far in excess of the actual GOR that's been realized in the field, which has been between 1000 and 1500.

We would like to next turn to the tab marked Section A. It is a reservoir fluid study performed -- it is information taken from a reservoir fluid study performed for McHugh and Associates on the Loddy No. 1 Well.

We would like to make the point with respect to any kind of fluid analyses that in order to have a valid fluid analysis the reservoir fluid cannot be disturbed either prior to the sampling, either by production from the field or by pressure drawdown at the well itself in which the sample was taken. In essentially all of the fluid samples which we've seen presented by Mr. Greer, there is a very distinct possibility that the drawdown in the vicinity of the wellbore was sufficient over an extended period of time to cause gas to come -- to evolve from the oil, such that the gas that's recovered in the sample chamber is less than that originally contained in the oil.

Once again, if this is not the case, it's very difficult to explain the production of free gas prior to after 200,000 barrels of cumulative production.

We -- we have reviewed the Loddy No. 1 data. If we would turn in this particular set of information back, let's see, there is the title page, there is a page that gives reservoir fluid analysis, formation characteristics, and well characteristics. Following that is a summary of samples received in laboratory. Following that is a hydrocarbon analysis of reservoir fluid sample. Following that is a volumetric data reservoir fluid sample. The next page back, which is 5 of 12 is a pressure volume relations, and finally, on page 6 of 12 there is differential vaporization data presented at a temperature of 170 degrees Fahrenheit.

The -- this differential vaporization data goes from the lab test of bubble point pressure of 1482 at which they record a solution gas/oil ratio of 588, and then it goes for pressures below that.

It also indicates the relative oil volume factor column, which is the third from the left.

If we would read subscript 1 on the solution gas/oil ratio column, it indicates cubic feet of gas at 15.025 psia and 60 degrees Fahrenheit per barrel of residual oil at 60 degrees Fahrenheit.

It does not indicate that that is per barrel of stock tank oil.

Reservoir engineers before they perform reservoir engineering calculations have to make the conversion from a residual oil basis to a stock tank barrel oil basis. In order to do that you have to use separator tests run on the crude sample that reflect the field separator conditions.

So the differential vaporization data presented on page 6 of 12 cannot be used directly in reservoir engineering analysis.

To the best of my knowledge in reviewing all the data that's been -- or all the calculations that's been done on the Canado Ojitos Unit, as well as on the Gavilan-Mancos Pool up to this point in time, nobody has made that conversion, which is required and is very clearly explained in classical reservoir engineering texts, such as Amex, Bass, and Whiting. (sic)

It is essential to make that -- that correction before you do any reservoir engineering analysis and that is the reason we have separator tests.

Now, when we said that we used separator test data, contrary to what Mr. Greer said that that's highly inaccurate, basically it is extremely necessary to make that separator test correction to the differential vaporization data prior to using the data in the calculations.

So we have basically used the differential vaporization corrected for actual field separator conditions, which has not been done by any of the other parties to the best of our knowledge.

We would like to move from that particular chart to the next tab in Mr. Greer's exhibit, which is charts -- or which is Tab B.

Followiong Tab B there is a set of rock property curves, relative permeability of fractured formations, plotted as versus total liquid saturation percent of pore space. As we indicated in our testimony and as Mr. Greer has indicated in his testimony, the curves used in calculation are the same one as shown by the dashed line.

For some reason, well, the next page, the pink page is an expansion of the chart, particularly for values of total liquid saturation in the lower end of the range, or the higher end of the liquid saturation range, running from 90 to 100 percent total liquid saturation, and he indicates that there is a non-linear behavior in that, in that area, and hypothesized, perhaps, I didn't take into account this non-linear behavior.

I would say that if we took the results of my Horner solution gas drive analysis, the values of KgKo versus total liquid saturation and plotted those points on this non-linear relative permeability curve, we would find that my points fall directly on top of that curve.

So it is not a matter of using incorrect relative permeability data.

If we would turn to the next page following the pink sheet, turn to the gold sheet, which is titled Calculated Solution Gas Drive Production Histories for Fractured Formations, and we see a plot of pressure and producing gas oil ratio versus recovery, we would note on this particular -- on this particular chart that at a given pressure level the gas/oil ratio should be relatively constant for the field, and it's not constant for the field. There are wells that produce widely varying GOR's. We've seen examples of wells presented by Mr. Roe in his exhibits, which we'll look at later, that indicate very high GOR's, but there are many, many more wells that have much more moderate GOR's that are not increasing to the extent that

Mr. Roe indicated that the McHugh wells are increasing.

If we would turn to Tab C, this is viscosity data at 170 degrees Fahrenheit. I don't believe that I have any differences with this information.

So we then move beyond that tab to Tab D, where Mr. Greer has calculated -- he's calculated the liquid saturation for the Native Son No. 2 for four points in time, December, 1985, through June, 1986. He's used the data that's shown in that calculation. He's used an equation that's designated with an asterisk.

At the bottom of the page it says the relative permeability ratio is equal to this producing GOR, which is R minus the dissolved GOR, and then it is adjusted for Ug and Uo and there should be a division sign between the Bo and the Bg values; those shouldn't be one following right on to the other. That's not correct.

But we would use the exact same equation. We believe that is a good indication of what KgKo is and from that we could imply some liquid saturation for the well itself.

The one thing that we would have to note about this is that this calculation assumes that all the gas is coming as solution gas from the oil zone and it doesn't give any possibility for gas coming from the gas cap itself or from the higher regions of the reservoir to make this kind of calculation.

But we would note with respect to that, if we skipped over the green page and we went then to the KgKo estimates from the Native Son No. 2 production data, that for the assumed bubble point pressure of 1500 psi, that the points that are shown December '85 through June of '86 fail to fall on the dashed curve, which is a curve of relative permeability ratio versus liquid saturation.

If we were to assume a higher bubble point pressure those curves once again approach the dashed curve that is shown -- shown on the sheet.

It appears that the assumed bubble point pressure of 1600 psi tends to give the best match to the dashed curve, indicating once again a higher bubble point pressure than that reported on the laboratory analyses, so once again we don't believe the laboratory analyses are correct. We recognize the difficulty in making this kind of calculation because the gas from the Native Son No. 2, we don't really know if it's coming from the oil zone or from the gas, the gas saturated region at the top of the reservoir.

If we turn to Tab E, there is a section taken from our report on the fluid properties. This section, which is highlighted, states that the remaining samples were both taken after significant production from their respective pools and it could not be determined if the lab reported bubble point pressure reflected true reservoir conditions or if some gas evolution had occurred prior to sampling.

Once again gas evolution can take place because of withdrawals from the reservoir as a whole or it can take place as a result of withdrawals from the specific well that is -- from which a sample is being taken.

He charactertized as taking a higher bubble point pressure a desparate act on our part. It wasn't a desparate act on our part. It was simply trying to take a bubble point pressure that gave us a gas/oil ratio performance consistent with observed field performance for the Gavilan-Mancos Pool.

We would also note that in his direct testimony Mr. Greer testified initially that the reservoir oil in the Gavilan-Mancos Pool may have been very close to the bubble point pressure at the time it was -- was described.

If that is the case, then I would have to say that our value of 1770 is more accurate than what's indicated on the fluid property analyses.

I would like to turn to the second of the foldouts which is in that section, that shows a -- the log sections for the Howard No. 1-A, the Canada Ojitos Unit E-6, the Canada Ojitos Unit J-6.

On these particular logs certain sections have been shaded based on, it appears, their silt content, as indicated by the resistivity logs, so that we see, we do see the gray zone, the A, B, and C zones.

We also see the difference in operator philosophies out there in the sense that the Canada Ojitos wells were perforated primarily in the silty intervals, whereas the Mallon well has been perforated from top to bottom.

All wells have been subjected to a large frac job. The results on the Mallon wells indicate that there has been sand entry throughout most of the reservoir. We would think that that large frac job establishes vertical communication. We would point also to the testimony of Mr. Habenmeyer (sic), who indicated that the frac log surveys indicated a presence of fractures over an extended vertical interval.

We would also refer to a recent core taken in the last few days from the Davis No. 1 Well, which in essentially all of the samples that have been looked at thus far over approximately a 200-foot interval have indicated vertical fracturing with as much fracturing taking place in the shales as takes place in the siltier sections.

That particular core also, in some cases they've observed fractures, more than a single fracture, more than one parallel fracture in the core itself, so we know that the fracture density is quite high.

They've also observed intersecting fractures in at least one case, so all fractures are not necessarily oriented exactly -- exactly parallel.

MR. LOPEZ: I think Mr. Rueni said Habenmeyer (sic) and I think it's Emmendorfer.

A I'm sorry, that's correct.

We would note with respect to this that one of the comments that was made dealt with the productivity of a well in which both the A and B zones, I believe, were perforated and stimulated, and that a bridge plug was set between the A and B zones. The A zone was not terribly productive, so the bridge plug was withdrawn and the production increased.

With respect to that comment we would have to say that that is normally to be expected. You complete in the larger section, you get more productivity, and that is basically what we would expect from a particular well. I don't necessarily believe that that means that there's no vertical communication between the two zones.

Following the foldout is a correlation of bottom hole sample data. These correlations that are presented here, and in general all correlations for oil properties, are based on certain assumptions and one of those assumptions is that the gas that is recovered from the well is all that is dissolved in the oil at whatever the reservoir pressure is at the time the well is flowed.

In the event the gas escapes from the oil prior to reaching the wellbore, or in the event that free gas is produced, these correlations are not valid. In using such correlations, therefore, it's simply making the assumption that -- well, it's basically assuming the answer and then -- and then using the correlations to prove the answer.

Turning beyond the yellow sheets to the comparison of core analysis with gamma ray induction log information, we would note that this particular well that is shown here is a well that's not located anywhere in the vicinity of Gavilan-Mancos Pool, and we cannot comment as to the relevancy of that particular pool with respect to the Gavilan-Mancos Pool. We believe that there are signficant differences between Gavilan-Mancos and the Canada Ojitos Unit. In that, between those two areas we might expect that -- that if we go even further away, that we would still have other differences that would occur.

We talked, or mention was made of a 600-foot producing interval being -- that we had used a 600-foot producing interval as being the basis on which we made our calculations.

We used a 600-foot interval as perhaps the maximum thickness that we saw productive out there in order to arrive at a permeability. By dividing by 600 feet we ended up with a lower permeability estimate than we would of had we used, say, 200 feet or 300 feet.

We frankly are not sure what the overall producing interval thickness is ourselves, but we felt that we would err on the conservative side, get a lower permeability, if we used the maximum thickness that we say, and that is typically perforated by many operators out there.

Q Would you care to comment on your opinion with respect to whether -- whatever that is, whether it's consistent throughout the pool?

A The --

Q The producing intervals?

A Well, the producing interval is not going to be -- is not necessarily going to be consistent throughout the pool. That is going to depend on the degree of fracturing and the degree to which those fractures are interconnected.

It also will depend on -- potentially on the completion interval and the size of the frac job, as well.

If we would move to Tab 5, or I'm sorry, Tab F, in which the history is presented for the Canada

Ojitos Unit No. 2. Prior to actually recovering a fluid sample that's used in the analysis, we would note that in this producing history, that the well produced several days before it was sampled. It was a low productivity well. It had a high pressure drawdown. That pressure drawdown was shown on the pink sheet.

It showed a well flowing pressure as low as 800 psi at the wellbore, such that -- which considerable below what any of us believe the bottom hole pressure or the bubble point pressure might be for the particular reservoir.

So there is certainly ample opportunity for gas to escape from the oil during this period of pressure drawdown prior to actually recovering the sample itself in this particular well.

So once again, we have the possibility, not only the possibility, the probability that the -- that some gas had escaped from the oil prior to sampling and as a consequence the bubble point pressure was higher than recorded on the CORE Laboratories information, which was presented in the yellow sheets, or the gold sheets for that particular tab.

If we turn to Tab G, the Canada Ojitos Unit L-11, once again we are presented with the operations that occurred at completion and then mention was made that this well produced over 100,000 barrels of oil prior to actually being sampled.

There was an attempt made to produce the well at low rates for a period of time prior to sampling but it's highly unlikely in this fairly thick reservoir that sufficient oil was withdrawn during the conditioning period to actually remove all the oil that might have a lower gas-/oil ratio, and once again, there was substantial production that occurred in this particular well.

If we would now turn to Tab -- no, still under that tab but following the yellow sheets, we would turn to the white sheet, which is a presentation of pressure versus cumulative production for the Canada Ojitos Unit. It is the pressure measured at datum of plus 1195 feet expressed in terms of pounds per square inch versus cumulative production in hundreds of thousands of barrels.

In this particular plot, if I heard correctly, there was an indication that the field produced for a period of time at pressure above the bubble point, at which point during which time the pressure decline was 3000 barrels of oil produced per psi pressure drawdown in the reservoir.

Subsequently, when the entire reservoir fell below the bubble point pressure, the rate of pressure decline decreased from 3000 or -- well, it decreased but it caused then an increase in recovery per psi -- per psi drop of reservoir pressure, and such that we then went in the period from 8-million to 12 -- from 800,000 to 1.2-million cubic -- barrels of production. We then had a 7000 barrel per psi pressure drop.

If you would recall the pressure versus cumulative production plots that we showed in our exhibit, we showed that pressure versus cumulative production is not concave upward. In other words, the pressure tends to be -- stay flat for an extended period of time and it's actually maybe increased a little bit withi increase in production recently.

In other words, we don't have this two -- two slope curve of pressure versus production that's presented for the Canada Ojitos Unit. That is indicative of the fact that the reservoir in the Gavilan-Mancos Pool was at the bubble point to begin with, and continues above the bubble point. We've never seen any kind of break indicating a change in the number of barrels that can be produced per psi drawdown in the reservoir.

And we have pointed that out previously.

The other thing that might be of interest is the fact that in the Canada Ojitos Unit this break occurs at approximately July 20th, 1965, when the pressure is at approximately 1520 psi, measured at a datum of 1195 feet. That was after production of what appears to be about

300,000 barrels of oil.

If we were to correct from the datum depth of 1195 feet down to a datum depth of 370 feet, which is more appropriate for the Gavilan-Mancos Pool, then we would add on approximately 240 psi to the point at which this curve breaks. That would put the pressure in the Gavilan-Mancos Pool at which this break would occur at about -- at over 1700 pounds, approaching 1750 psi, once again an indication that the bubble point pressure in the Gavilan-Mancos Pool is more on the range of 1750 psi.

Q Greg, I think earlier on this point you misspoke and said production above rather than below the bubble point.

I think this is a very important point in our presentation and would ask you to go over this point again, if you would, please.

A Okay. The pressure versus cumulative production plot can be -- well, if we have a reservoir that has pressures that are in excess of the bubble point pressure, in other words, we have no free gas, the only thing that can take the place of the oil that's been withdrawn from the reservoir is the expansion of the remaining fluid, plus any, let's say, contraction of the pore space itself. And as a result of that, those two being the only influences we can see, we would expect to see pressure drop quite rapidly as fluid is withdrawn from the reservoir.

So -- and then when we go to pressures below the bubble point where we have a free gas saturation in the reservoir, then that gas has a great -- greater degree of compressibility or expansibility (sic) and so we can take out, provided we don't take out the gas with the oil, we can take out more oil and per psi of pressure drawdown.

Normally you expect to see in a reservoir that is what we call under saturated or above the bubble point, you expect to see a period of rapid pressure decline followed by a period of less substantial pressure decline, and that is what we've observed for the Canada Ojitos Unit, but it is not what we have observed for the Gavilan-Mancos Pool.

We have a final tab in that presentation. It is Tab H. It is the production history taken from our report for the McHugh Native Son No. 1 and the Homestead Ranch No. 2, indicating a very low gas/oil ratio for those two wells, for those two particular wells.

We had used that as evidence of migration already occurring. That's not our only evidence of migration but that is one, one set of evidence of migration. It was pointed out, and I think probably correctly so, that -- in fact, Mr. Lyon pointed it out -- that for that kind of low GOR that we see for the Native Son No. 1, that is not consistent with what the flowing bottom hole pressure would be.

So I would have to agree with Mr. Greer that there is undoubtedly some problem with the reported gas production on this well. I don't know what it is but it does appear that these wells are low gas/oil ratio wells. Unfortunately, if the reported data isn't correct, I don't know what we have to work with.

That -- that concludes my review of Greer's exhibits that are contained in this yellow volume and --

Q You might as well move right on to the other volumes.

A Well, I had an exhibit that I'd like to present.

Q Okay, why don't you turn to Exhibit Number Twelve --

A Number Twelve?

Q Exhibit Twelve.

A All right.

Q Okay, I'd ask you to refer to what's been marked as Exhibit Number Twelve and ask you to discuss it.

A Exhibit Number Twelve is a calculation of oil in place using a material balance approach for the Gavilan-Mancos Pool based on the pressure production history that we had presented in our direct testimony, but instead of using a bubble point pressure of 1,770 psi we've revised our fluid properties to include the fluid properties from the Loddy No. 1, which had a bubble point pressure of 1496 psi.

So we have replaced our table fluid properties in the middle of the page with -- that reflected a higher bubble point pressure of 1770, with these -- this new set of bubble -- of fluid properties from the Loddy No. 1.

The bottom of the page indicates the results of our oil in place calculations. In our direct testimony we indicated that there would be a period of time in which the reservoir was undersaturated or was partially undersaturated, such that the oil in place calculations could not be used during that -- that period of time.

As it turns out, in the event that we are so undersaturated that the bubble point pressure is down around 1500 psi, then we will not reach a partially undersaturated condition through at least 1985, so the values of oil in place that are calculated up to 1985 are the values that should be representative of the reservoir, and I think in reviewing this we can see that the oil in place value that would be calculated in this manner is in excess of 400-million barrels. That's just saying that if we can take -- that if we have a reservoir that contains an oil with such a low bubble point, then we must have an awful lot of reservoir down there to take out the amount of oil that we've taken out, seeing the kind of pressure drop that we've seen.

We do not believe that the oil in place value of 400-million barrels is correct. We don't believe probably that any other people would -- would feel that same way.

We went through this type of reasoning when we were doing our study as a basis for, once again, appraising what the value of the bubble point pressure was and we -- this is one of the reasons that we once again elected not to use a 1500 psi bubble point pressure. We elected to use the 1770 psi bubble point pressure.

Q Okay, now going to the next volume of exhibits introduced this morning, would you care to comment on those?

A Yes. The next set of exhibits that I have in front of me are contained in a -- in a brown folder. I'm not sure what the exhibit number was on this.

Q Exhibit Seven?

A Exhibit Seven. On this the first tab following -- in Exhibit Seven is followed by a yellow sheet talking about comparison of porosity and permeability for two systems of fracturing.

MR. STAMETS: I believe that's

blue.

A Wait, what color did I --

MR. STAMETS: Yellow.

A Yellow. After awhile you get color blind, after awhile.

Okay. The first page following Tab A is indeed blue and it is a comparison of porosity and permeability for two systems of fracturing.

The -- I believe that -- well, the point that we would like to make on this is that we believe that over the Gavilan-Mancos area that there has been, perhaps, more than one event that's led to fracturing, not a single event such as a flexuring shown here, and in combination we would expect that these multiple events would give rise to -- to different degrees of fracture, fracture density and not necessarily a variation in fracture width.

So once again, we are now prepared to accept the proposition that porosity is related to the cube root of permeability. That is one possibility but we recognize that in a geologically complex situation that is just one of multiple possibilities.

We would like to turn, then, to Tab B. Tab B has a yellow sheet following it.

There are several points that are made here. If I were to read the first part of this presentation simply stating, "With respect to Mr. Hueni's response to the chairman's questions about interference tests conducted in the Canada Ojitos Unit, we assume that Mr. Hueni apparently did not understand the nature of the subject interference tests for his responses were to the effect that:

1. Interference testing can only show information about the formation between the test wells and is complicated by fracturing.

2. The EI, or exponential integral straight line solution does not apply to a heterogeneous reservoir; and

3. The best way to determine the reservoir characteristics is from individual well pressure build-up tests."

With respect to this we would once again repeat, the best way to determine reservoir characteristics is from individual well pressure build-up tests.

We would also repeat that the EI straight line solution does not apply to a highly fractured reservoir. We would like to present our next --

Q Exhibit Thirteen. In this connection and in response to the comment, I now ask you to refer to Exhibit Thirteen and explain why you would introduce this exhibit.

A Following the statement --

Q Okay, I think we're all with you.

A The final paragraph following those three points states that, "Since all three of these statements are incorrect as to the subject reservoir and tests, it is assumed that Mr. Hueni didn't have time to study them so his failure to correctly assess the tests is understandable; however, his statements are in the record and the record needs to be set straight."

I'd like to turn now Exhibit Thirteen, which is a paper published in October, 1983, by the Society of Petroleum Engineers in the Society of Petroleum Engineers Journal.

It is a paper written by Tatiana D. Streltsova, a researcher at Exxon Production Research Company, assigned to study naturally fractured reservoir behavior.

The first page is simply the cover sheet from that paper.

The second page indicates that the -- that there is a section of that paper that deals with interference test analysis; talks about pressure pattern for interference test analysis.

And on the third page highlighted is the statement that we would like to set the record straight with.

"Therefore, if one uses a conventional analysis based on the EI curve which does not take account the pressure support offered by matrix blocks on drawdown measurements, then the calculated formation permeability will be overestimated."

Not only will the formation permeability be overestimated but so will the storativity (sic) of the reservoir.

This is the basis on which we said that the permeability and storativity (sic) numbers presented earlier in Mr. Greer's testimony are higher than we believe -- than properly reflect actual reservoir parameters. That is the reason that we have gone with pressure build-up analyses. In fact, if we were to read this entire paper, we would see that a conventional Horner plot used on a single well, pressure build-up survey, would provide reasonable estimates of fracture conductivity.

Q What is your opinion will respect to the value and reliability of the paper?

A I believe that this is the most recent information that is available on naturally fractured reservoirs in terms of pressure transient testing. They have taken this and they've -- basically they've updated the work of Warren and Root, which has been quoted in Mr. Greer's testimony, and have shown the failings of the Warren and

Root model, and they've used the data presented by Warren and Root, reanalyzed it using the techniques developed in this -- in this paper and have showed the consistency of results.

Q If necessary, would you make the entire paper available to the Commission?

A Yes, I would.

Q Okay.

A One final point that I might make with respect to the yellow sheets in that tab, or on page 2, item 2, there is a statement in the Canada Ojitos Unit test area, the geometry of the reservoir is that of individual tight blocks surrounding by a high capacity fracture system.

Once again, this is exactly the same type of situation identified by Stretlsova in the paper that we've just referenced to.

From there on I would have no comments on the exhibits, simply from the fact that I don't believe the exponential integral solution is the appropriate way to analyze the tests.

Q Okay, now would you refer to the final volume I think was introduced this morning, Exhibit Eight?

A Yes.

Q And have you comment on that.

A Exhibit Number Eight, which is presented in the black folder, on the Greer testimony, in reviewing that information we would like to turn to Tab A and following Tab A there is a title Geologic Analysis in Naturally Fractured Reservoirs, and then following that sheet we see several plots of -- and one in particular that was highlighted in pink, it's Figure 1-56, "Fracture porosity as a function of fracture width and fracture spacing".

If I understood correctly, the fracture spacing that was selected from this particular exhibit was a fracture spacing of 1000 centimeters, which I believe approximated 30 feet, if I understood correctly.

We would note from the information that we have available in terms of fracture density, we would think that the fracture density of one well per 30 foot is -- is excessively large. It would be much smaller than that or that there would be a much tighter fracture spacing than that that's shown highlighted in this particular exhibit.

The significance of that, if we would turn, then, to Tab B, if we had a much tighter fracture spacing we believe that the graph that was shown under Tab B, it is the fourth page back, it has a blue line on it, showing radius of circular drainage area versus producing time to establish steady state conditions in days, that if we had a much tighter fracture spacing, the length of time required to establish steady state conditions would be much shorter than is shown on this particular graph.

So that to infer that the matrix cannot contribute significantly, or the tighter portions of the reservoir cannot contribute significantly, is based simply on the assumption of the fracture spacing and if that fracture spacing is not correct, then the extended length of time predicted by this plot for a response to occur is considerably overstated.

We would turn then to -- to Tab C, the Warren and Root paper under the Behavior -- titled The Behavior of Naturally Fractured Reservoirs, and highlighted in that is item number 3, "Since the build-up curve associated with this type of porous system is similar to that obtained from a stratified reservoir, an unambiguous interpretation is not possibly without additional information."

This is basically the exact same statement that we made in our direct testimony. We reviewed the pressure build-up surveys. We identified places where it occurred. We had dual porosity system, and we said that in our analysis that it was not critical that we had matrix porosity but we thought the possibility existed and we recognize the fact that this highlighted statement is somewhat true, that it -- that in a pressure transient test such as this it is extremely difficult to differentiate a stratified reservoir from a dual porosity system.

But nevertheless, we believe that it is

certainly a reasonable possibility to think that matrix contribution exists.

I'd like to turn to Section E, which is the conventional core analysis for Mobil's Lindrith B No. 38 Well. This presents the results of the CORE Lab studies, showing helium porosity as well as fluid saturations in terms of oil and water saturation.

In the center, in the top center of the page under the date and under the formation, it talks about the drilling fluid and in the drilling fluid it talks about it being water based mud.

To the extent that water is used as a coring fluid, we would expect some alteration in the water saturation of the -- of the core itself. To what extent that actually occurred is difficult to determine. If you want to obtain an accurate value for water saturation you normally core with an oil base mud.

So to assume that the water saturation number as shown on -- on the CORE Lab report is accurate, is -- is not correct.

So if we were to turn, then, to Tab F, followed by several yellow sheets, or a couple yellow sheets, and we were to look then at the saturation shown in columns three and four, we would see that those saturations are exactly the same saturations as -- as taken form the CORE Lab report.

We would note, however, that those saturations in column four, the water saturation, is undoubtedly disturbed by the fact that they used a water based mud system, such that when they take a water saturation in column four and subtract it from 100 percent saturation, the initial reservoir oil in place value that's shown in column five is not correct. It is understated.

The water saturation in column four is not the connate water saturation of the rock as it existed in the reservoir.

So the calculations that follow that are not particularly meaningful, because those are not the correct saturations.

If we would turn to the first tab following -- or the first page following Tab G, which is a plot of water saturation versus permeability, taken from the core data of the Mobil Lindrith B No. 38, this is just an illustration that it's not reasonable because the direction of that trend is to the upper right and as was shown two pages later by the -- by the pink tab, the trends for other fields, such as Rangely and Elk Basin, are in a trend running from the upper left to the lower right and the Lindrith B-38 is just opposite from that trend.

Well, if we were to look back, then, at the gold trend, that says simply that it is incorrect to plot water saturation versus permeability with the water saturation taken from the core data because that is not connate water saturation and that's exactly what that -- that gold sheet implies.

We would finally turn to the last section of this exhibit, which is titled Section H, and we note under the sample description, we see sample descriptions primarily of shale, and we see almost the way through that the interval is fractured. Once again this is not a well that is locateds directly in the area, the study area that we're concerned with but it does illustrate that shales as well as silts are fractured, such that vertical communication can exist within the reservoir.

Q Having heard Mr. Greer's and Mr. Roe's testimony today, would what you've heard and analyzed change the conclusions you reached last Friday, and I'd ask you to elaborate and in this respect ask you to comment on Exhibit Fourteen, when appropriate.

A Okay. The conclusions that we drew last Friday, we feel that at this point there is no reason to change those conclusions.

Once again we believe gas segregation is occurring. We believe that we have a reservoir that is at a pressure below the bubble point pressure, that it's been that way for a substantial period of time. The gas has evolved from the oil; that it has migrated away from the well to some extent, not completely. There is always some lateral movement of gas as well as vertical movement of gas, resulting in -- in whatever the observed gas/oil ratio values are.

With respect to that point, I would like to comment on Mr. Roe's exhibit, that was titled Dugan Production Corporation Exhibit Number Three, and at the -- at the final three pages of that exhibit, which are titled Exhibit Number Five, are gas/oil ratio plots and production plots for three wells, three of McHugh's wells in the field.

We would like to note with respect to those three individual well production plots that those three plots are all -- are for wells that are all located in a high depletion area of the field, more or less following along this northwest/southeast trending direction that we've identified through fracture orientation logs, as well as through some fault mapping; that these gas/oil ratios are in structurally down -- or in structurally intermediate wells, not in the structurally highest wells; that the gas/oil ratios have gone up in response to increased production in those specific wells; that they are not representative of current GORs in many of the wells in the field.

For example, we could take the current GORs for the Mesa Grande wells and we would find that those in many cases are in the range of 1-to-2000 standard cubic feet per stock tank barrel.

So once again we realize the gas/oil ratios can increase very rapidly with a small increase in gas saturation in a given area of the reservoir. We believe that those -- that that particular area of the reservoir has experienced high depletion, historically high depletion, and it is -- has a slightly higher gas -- gas saturation in that area and higher gas/oil ratios as a result.

In the Mallon area of the field, based on July production, the Ribyowids 2-16 had a GOR of 1978.

The Fisher 2-1 had a GOR of 1,085.

The Howard 1-8 had a GOR of 1344.

The Howard 1-11, a GOR of 2214.

Once again we see variations between individual wells in the field. We don't see GORs that are necessarily as high as they are on the McHugh wells as presented in Exhibit Five.

Q I think you're referring to the McHugh wells as Exhibit Five, not Exhibit Three?

A Well, it was attached to Exhibit Three.

Q Okay, I think it is

A Okay.

Q And not Exhibit Five, and in this connection were any of those wells -- do any of those wells have commingled production?

A As a matter of fact, in reviewing Exhibit Five we do see commingled production for the ET No. 1 and we note that the amount of gas that's allocated from the Dakota is only 6 percent. A higher drawdown in that well, associated with incresed production, may have resulted in higher gas production out of the Dakota. That's certainly an unknown at this point in time.

The other commingled well is the Janet No. 2 and it has 10 percent of its gas allocated as coming from the Dakota, of its total gas.

So once again, higher producinc rate in that well, we are not sure if there's still 10 percent of the gas coming from the Dakota.

The only well that is a single Mancos producer, I believe, is the Native Son No. 2, and in that particular well, while we have an increasing trend in GORs, it is perhaps not quite as high as the other wells.

Q I'd now refer you to what's been marked Exhibit Fourteen and ask you to discuss this.

A Exhibit Number Fourteen is a presentation of the amount of gas production that is -- would be withdrawn together with the oil production, and depending on the gas/oil ratio limit.

Under the present allowable scheme and for the Mobil proposal, unrestricted production limited only by the depth bracket allowable would result in 702 barrels a day of production with a 2000 GOR, implying that as much as 1.4-million cubic feet of gas could be withdrawn from -- from the reservoir, together with the oil.

The McHugh proposal at 200 barrels a day and 1000 GOR represents a reduction down to 200 MCF per day, which is a substantial reduction.

In the event that the McHugh proposal were increased in terms of the oil production rate a bit, but on the other hand, the gas/oil ratio declined down to a value of let's say 538, then the gas allowable would increase a bit but would still not amount to the volume of gas proposed by either Koch or Mallon.

The Koch proposal would provide for a gas allowable of 413 MCF per day; Mallon-Mesa Grande proposal, 453 MCF per day.

Once again, in our direct testimony, based on the segregation tendencies of gas and oil, physical properties as we can best arrive at them for the Gavilan-Mancos Pool, we have actually calculated a gas withdrawal rate in excess of this 453 MCF per day value that we propose as being sufficient to be withdrawn while still not doing any kind of damage to the reservoir, still permitting the gravity segregation tendencies to occur within the reservoir itself.

So the Mesa Grande-Mallon proposal does represent a substantial reduction in the amount of gas production that would come with the oil, and once again it is our conclusion and our belief that it is the gas, free gas production taken from the reservoir, together with the oil, that does damage to the reservoir.

We believe that a low GOR provides the incentive to the operator to do the work that is necessary to reduce the GORs. That means sealing off the upper portions of the productive interval. Then that provides an incentive for them to do that.

MR. STAMETS: Excuse me, did you say the proposal is to lower the GOR to 626?

A That is what our proposal was, was to lower the GOR but not to change the oil -- oil rate.

MR. LOPEZ: One hour and 25 minutes, Mr. Stamets.

MR. STAMETS: All right. That's very good. Are you all through?

MR. LOPEZ: We reserve the rest of our three hours to see what we can do with it.

MR. STAMETS: Okay. I just somehow think we've already got more hours here today than I had planned on because of the 47 minutes that the pros had left over there.

The opponents have completed their direct re-whatever today.

MR. KELLAHIN: Does that include Mr. Pearce?

MR. PEARCE: Yes, it does.

I try to help, Mr. Chairman.

MR. STAMETS: Do you choose to use any of your time in cross examination?

MR. CARR: I might have just one question in cross examination.

We will ask for a brief recess and then we'll be recalling Mr. Greer for some brief testimony, which might not require our 47 minutes; might not require even 42.

CROSS EXAMINATION

BY MR. CARR:

Q Mr. Hueni, you've studied the reservoir, the Mancos, in this area and as I understand your testimony, you have come up with a theory about the segregation tendencies within that reservoir of the gas and oil; gas moving up, the oil moving down.

In his first exhibit, Section H, Mr. Greer pointed out some shortcomings in that, the base data. If I understood your testimony, there may be some difficulties there but that's what you had to work with, now is that correct?

A I'm sorry, which section were you referring to?

Q H, H in Exhibit One, the yellow book.

A We used the data from the Engineering Subcommittee.

Q And if there are problems with that data, that still was what you had to work with.

A That is correct.

Q And if there are problems with that data, it might affect your conclusions.

A I -- I think it would have to be in terms of identifying the reservoir drive mechanism. I think it would have to be extremely substantial problems with the data.

Q So you don't need very good data to get your conclusions.

A To get -- to understand what's directionally correct, that is the case.

MR. CARR: Thank you.

MR. STAMETS: Mr. Kellahin, any questions?

MR. KELLAHIN: No, sir.

MR. STAMETS: This witness may

be excused.

And you all would like a few minutes?

MR. CARR: Yes.

MR. STAMETS: We'll take a fifteen minute recess.

(Thereupon a recess was taken.)

MR. STAMETS: Mr. Lopez, would you like to introduce your exhibits?

MR. LOPEZ: Yes. I would.

Were Exhibits Twelve through Fourteen prepared by you or under your supervision?

MR. HUENI: Yes, they were.

MR. LOPEZ: We'll tender Exhibits Twelve through Fourteen.

MR. STAMETS: Without objection they will be admitted.

Mr. Carr, do you have some redirect, or Mr. Kellahin?

MR. CARR: I have some redirect for Mr. Greer.

MR. STAMETS: Are you ready?

MR. CARR: Yes.

ALBERT R. GREER,

being recalled and remaining under oath, testified as follows, to-wit:

REDIRECT EXAMINATION

BY MR. CARR:

Q Mr. Greer, you've been present this afternoon for the testimony presented by Mr. Hueni, have you not?

A Yes, sir.

Q I'd like to direct your attention to Benson-Montin-Greer Exhibit Number Six, the yellow book, and first direct your attention to the pink page immediately preceding Tab A and ask you to respond to Mr. Hueni's comments concerning this exhibit.

A Yes, sir. Mr. Chairman, I understand that -- what I understood Mr. Hueni to say was that they used this method all over the world and therfore it's okay.

I'm really disappointed. I had hopes that during the noon hour they would have called their office and had a new run made by their computer with points more closely spaced to give us a more accurate reading, but they had time to do some other things with their computer but they didn't evidently have time to do that.

There's no question that the calculated curve is in error. They just don't know by how much, and the fact that it works in the North Sea or Egypt has no bearing on this situation because the problem is in reservoirs that have relative permeability ratios that are considered good, most of them have a critical gas saturation which is fairly high, 5 to 10 percent, and so a large volume of oil can be produced as gas saturation picked up before the KgKo relation picks up real fast, and in that situation you can take big steps and it doesn't make much difference.

So, then ordinarily in the North Sea and other big oil producing areas of the world they have these good resevoirs that -- that really are easier to analyze in this respect than ours.

Q Now, Mr. Greer, would you go to Tab E in this exhibit and to the cross section contained in that, the third document, third page.

A Yes, sir.

Q And I'd ask you to relate the information on that to recent information from the Mallon core.

A If we could look under that section over to the cross section, we've heard once again how there's so much vertical communication among these zones and up and down the formation, and that it shows up in cores as well as vertical communication being caused by fracture treatments.

I'd say first with respect to the fracture treatments tying the zones together, we have done that and they haven't been tied together, and we've demonstrated that.

Now, on the core that the companies have jointly gone together in their coring Mallon's Davis Federal Com 3-15, southeast quarter of Section 3, 25 North, 2 West, and it's my understanding that between the B and the C zones there have been no fractures found in -- in that core, which confirms what we've been talking about all along about the stratified nature of the reservoir.

Q Now, in that core, what zones were cored, do you know, in the Mallon well?

A Of the information I have they cored the A and the B zone and part of the C zone, and we had hopes they would get -- or I had hopes they'd get below the C zone a way, the area that we were interested in, but I'm not sure just where they quit.

Q All right, if you'll now go to Tab F, the blue page behind it and respond to Mr. Hueni's comments concerning the bubble point.

A Mr. Hueni's noted that the pressure had been pulled down to 800 pounds while we were testing the well, and therefore that the sample that we got would not be a valid sample because the pressure had been pulled down and the bubble point would be a false bubble point.

The thing that I point out, Mr. Chairman, that's kind of strange, is that if that's the case, why didn't we get a bubble point, say, at 900 pounds, 1000 pounds, 1100, 12, 13, 1400 pounds, and of course, one can say, well, that's just -- just happenstance.

It seems like strange happenstance that two wells that we took bottom hole samples on and Mr. Hueni says the pressure has been pulled down, the samples aren't valid, why would they check within just a few pounds of each other, and here's one that the pressure could have been as low as 800 pounds. If the sample had been contaminated, so to speak, by the pressure being pulled down to that point, it should have shown a bubble point of 800 pounds and not 1500.

Q Now if you'll go on to Section G and go to the beige pages, the brown pages in that exhibit and review what they are and why they were included?

A I would just point out once again how carefully we conditioned this well in order to get a bottom hole sample, and again when we got that bottom hole sample, it checked very closely with the other one that we had before.

We tested the well with a minimum bottom hole pressure of 100 pounds higher than the anticipated pressure and sure enough, we got a bottom hole sample that was a good sample, checked within a few pounds of the other one, and there's no way just by happenstance that would happen.

But Mr. Hueni then concludes that the bubble point is high, 1700 pounds.

Then Mr. Hueni goes over to -- to our pressure production graph and having said five minutes before that that the bubble point was like 1700 pounds, he comes along and tells us how this undersaturated reservoir, the pressure production coefficient changes. So it had to be undersaturated for that to happen.

So he's given us a contradiction when he says the bubble point is higher than 1700 pounds and yet he comes along and shows exactly the same thing that I did, how the pressure, the production pressure coefficient increases as the bubble point moves down the structure and the oil becomes saturated and the compressibility increases so that you get more oil for each pound of pressure drop.

Then Mr. Hueni, with Exhibit Twelve, instead of giving us what I had hoped he would give us, a computer run, tells us about how we could have 400-million barrels in place if we had a bubble point of around 1500 pounds, and could we introduce our Exhibit Nine now?

Q Will you now refer to what's been marked as Exhibit Number Nine? I'd like to have you identify it, identify it and then review the information contained on that exhibit, please?

A Mr. Chairman, this is an exhibit that shows how the oil in place calculation can vary depending upon your choice of fluid properties that you use.

In this particular instance this graph is calculated on a pressure -- production pressure relation of 10,000 barrels per pound, and what that says for Gavilan at the time that about 10,000 barrels per pound of reservoir space was being voided, that if the oil were entirely undersaturated, we look at the upper line, then there would be some 400-450-million barrels of oil in place, similar to what Mr. Hueni shows on his Exhibit Twelve.

But I point out, Mr Chairman, if there's some free gas in that reservoir and there's only five percent, then the oil in place is more like 150-million barrels, or if there's 10 percent free gas in communication with the -- with the oil, then there's like only 100-million barrels in place, and I know that it seems strange that you could have free gas in communication with undersaturated oil in a reservoir. Most engineers will tell you that's impossible.

Mr. Chairman, we've studied in this area four reservoirs, Boulder, East Puerto Chiquito, West Puerto

Chiquito, on the west side of the Basin La Plata Mancos. In all four instances there was undersaturated oil in the reservoir, unquestionably undersaturated. In every instance there was a free gas cap and how much saturated oil there might have been below the gas and above the undersaturated oil, we don't have any idea, but in every instance that happened.

And the reason I prepared this graph, Mr. Chairman, was an an aid to the Engineering Committee in their study as to how the volume of oil that we're dealing with might depend upon these various factors, and the fact that the reservoir is stratified, the fact that there's free gas, there's no way, no way to tell exactly what you have, and the estimates that we've made, which show 100-million barrels in place, we've estimated that the system compressibility is such that about 80 percent was undersaturated at the time that we were making our estimates, about a 5 percent free gas, and that shows on this graph about 100-million barrels.

It's a rough estimate but this is how the oil in place varies, and so it really doesn't mean very much that they come up with this Exhibit Twelve and say that this is unreasonable, if you have a 1500 pound bubble point it doesn't mean a thing. You can still have a 1500 pound bubble point and still have maybe 100-million barrels in place and the reservoir performs something like it's doing right now.

Q Do you have anything further on Exhibit One -- or Exhibit Six?

A I think that's all.

Q Mr. Greer, was Exhibit Number Nine prepared by you?

A Yes, sir.

MR. CARR: At this time we move the admission of Benson-Montin-Greer Drilling Corporation Exhibit Number Nine.

MR. STAMETS: With no objection Exhibit Nine will be admitted.

Q All right, Mr. Greer, would you now refer to your Exhibit Number Seven and I'd ask you first to refer to the cartoon and diagram you prepared of different kinds of fracturing in formations.

A Yes, sir, the blue sheet, the comment that Mr. Hueni had was that there had been more than one event causing fracturing in the area. We still think that it could be like we've shown in Plate IV, and I would point out, Mr. Chairman, that that's exactly how I arrived at the presentation I have here, is that I assumed that there was more than one event; that in the first event you have certain fracturing and in the second event you have the fractures spreading.

Q Now would you now proceed back into the exhibit behind Tab B, and I'd like you to refer to the yellow sheets which relate to the interference testing information.

A Yes, sir. We'll refer to that and the paper, and I don't have the exhibit number of the paper that was presented --

Q This was Mr. Hueni's paper --

A Exhibit Thirteen, the SPE paper, and I'd point out once again, Mr. Chairman, that people dealing with fractured reservoirs have it so locked in their mind that there's only one kind of a fractured reservoir and that's a reservoir with matrix porosity and fractures in it, and of course that's what this paper has to deal with, which does not have anything to do with our pure, fractured reservoir in Canada Ojitos, and I would like to note that we made the interference test, we made determinations from that interference test that outside of the test area, this large area, which I say is being sampled by the interference test and which Mr. Hueni declines to comment on because he doesn't think the EI formula applies, we concluded that the transmissibility was some 20 to 40 times higher than what we measured in the individual wells, the average reservoir transmissibility.

Two years after we ran an interference test we drilled a well a couple of miles from the test area, and sure enough, we found the reservoir had that high transmissibility.

We ran a test after injecting gas, a steady state test that showed the transmissibility to be between 5 and 10 Darcy feet, just like we had calculated from our test.

So, Mr. Hueni says it doesn't apply. It certainly applied in our instance.

Q All right, Mr. Greer, are you now ready to go to the diagram you have (not understood) --

A Yes, sir.

Q The circle showing the wellbore correlation?

A Yes, sir, this is the relation where I show that the EI formula really does apply. It's under Tab B, where I showed the close correlation between the EI formula and the reservoir with the large internal radius, and Mr. Hueni refused to comment on that. I think it would be interesting, since it was a fractured reservoir he said doesn't apply.

If it's a homogeneous reservoir there's no question about it, no question about it, and still his statement that interference testing measures only the formation between the two wells is just wrong.

Q Now, Mr. Greer, will you go to your exhibits in the black book, Benson-Montin-Greer Exhibit Number Eight, and I'd like you to refer to the information you have behind Tab F concerning the water analyses on --

A Yes, sir. Mr. Hueni says that the saturations, the water saturations shown here, are not representative connate water saturations because water has been added by the drilling fluids. That's the very purpose of this -- of this first calculation on this yellow sheet.

It's pretty hard, Mr. Chairman, to push fluids into the core without pushing some oil out and that's what this is directed at, and it shows that with all those negative numbers, that it doesn't appear that there's a lot of flushing. If there's not a lot of flushing there's probably not a lot of contamination.

I notice that the water saturations used by the Mobil engineer pretty well fit the average as to what we show here, but I agree, I agree that there -- that the saturations shown here probably are not right. That's the whole point of the core analyses that we showed and how cooking the kerotin and the water hydration out of the shale completely invalidates the calculation which determines oil and water saturation. So that's my concern, Mr. Chairman.

I don't know. I don't think Mobil really knows. I don't believe anybody knows what that water saturation is and that's why I say it's possible to be assigned 100 percent and not any effective permeability whatsoever.

That's a possibility.

Q Mr. Greer, do you have anything further to add to your testimony at this time?

A No, sir.

MR. CARR: That concludes our re-rebuttal.

MR. STAMETS: Okay. Do you all have anything further?

MR. CARR: At this point we do not.

MR. STAMETS: Are there questions of Mr. Greer?

MR. LOPEZ: No.

MR. STAMETS: Does anyone have anything they wish to offer at this time, any additional direct testimony, cross examination, or are we ready for closing statements?

MR. LOPEZ: I have just two things to do, Mr. Stamets.

GREGORY D. HUENI,

being recalled as a witness and having been sworn and remaining under oath, testified as follows, to-wit:

REDIRECT EXAMINATION

BY MR. LOPEZ:

Q Mr. Hueni, you've heard what Mr. Greer just stated, so does this testimony in any way change any of the opinions or conclusions you've reached in your testimony this morning?

A No, it doesn't change any of my conclusions.

MR. LOPEZ: At this point before getting to closing I would like to offer our Exhibits Fifteen and Sixteen. They are letters addressed to the Commission by American Penn Energy, Inc., and Kodiak Petroleum, Inc.

The first letter from American Penn is dated August 26th, 1986, and is submitted by Mr. Al Hermanson, Vice President of Production. Mr. Hermanson attended all the hearing through last Friday but couldn't be here today.

The same is true for Mr. Kent A. Johnson, President, who signed the letter from Kodiak.

Apparently some of these exhibits have the signature page left off of them. I think if you just take a minute to read these two letters, rather than my reading into the record (not clearly understood), but I would like them included in the record.

MR. KELLAHIN: Mr. Chairman, we would object to formally including these letters in the transcript of the hearing. Obviously the witnesses are not available to authenticate the letters. I believe the custom and practice of the Commission is to allow various interested parties to submit communications directly to the Commission and have the Commission read them and use them for whatever purpose you want, but I believe they're not properly authenticated and ought not to be part of Mr. Lopez' case and marked as exhibits.

MR. LOPEZ: My response to that, Mr. Chairman, is I did enter my appearance on behalf of both companies at the beginning of the hearing. We have three hours to do with as we wish today. We've certainly heard from Mr. Greer on much hearsay, which he admitted as much this morning. It it's allowed in, I don't see how this is any different.

MR. STAMETS: The Commission will accept these exhibits and give them the weight that we have always given letters which have been received.

That is, we'll accept them for what they're worth.

We have also received a letter from Amoco Production Company which says a number of things including that it's their opinion that the applicants and protestants presented technically competent testimony concerning the reservoir and various production considerations.

The fact that the testimony presented was in part so diametrically opposite demonstrates the need for additional collective reservoir studies.

They say if we err, we should err on the side of the prevention of waste. They take no position on spacing and unitization issues; whatever we do should be of limited duration, not exceeding ninety days.

And there are copies here for everybody at the close of the hearing.

Are there closing statements?

MR. LOPEZ: I'd be glad to do it. Are there any comments from the audience? I mean I know the Howards are here but I don't think they could stand the distance, either.

But there are other people here.

MR. STAMETS: Feel free to go ahead. I'm ready to.

MR. LOPEZ: Mr. Chairman, Members of the Commission, I'm certain I can be quite brief. I think after five days you've either got it figured out or you're so hopelessly confused that nothing I could say could straighten that out.

I would first like to state that it is our position that there clearly is no crisis. We don't reserve to epithets and we will try and restrain ourselves from sanctimonious self-congratulation and the condescension that we saw evidenced on the other side and to which we take exception.

The position of Mallon and Mesa Grande in this case is one which is a sincere and intense attempt to reach what we consider to be a rational and prudent compromise between the two opposing views taken on the reservoir producing characteristics of the Gavilan-Mancos Pool.

We believe that the restriction on production based on the gas/oil ratio limitations, as we've recommended, is the only one that made sense. For the period during which the Technical Subcommittee can continue its work, it would seem, as we've recommended, that this period of study probably should be concluded by the time the whole issue of spacing on the Gavilan-Mancos Pool is re-examined by the Commission in March pursuant to its earlier order.

This is a classic case where Mr. Greer has gone from preaching to meddling. It has been demonstrated that Mr. Greer has no interest in the Gavilan-

Mancos Pool. His interest lies in the West Puerto Chiquito Pool.

There are three wells that I will address later, but which clearly lie on the western side of the permeability barrier or restriction, however you wish to characterize it, which have producing characteristics clearly more similar and identifiable with the Gavilan-Mancos Pool and which should be treated similarly.

The interests of Mallon and Mesa Grande have been demonstrated to be significant and large. The interests of the other working interest owners who support our position have also been demonstrated to be of significance and major.

We will hear that Mr. Greer has had twenty-five years experience in the Canada Ojitos Unit and that our various witnesses, because of their youth, and because of their inexperience in the San Juan Basin, which has not really been demonstrated, carry no weight.

I think quite the contrary. There may be some benefit to traveling outside of San Juan County and seeing how the rest of the world operates and how comparisons with other comparable reservoirs throughout the world may shed light and knowledge with respect to the producing characteristics of the Gavilan-Mancos. So if it is a condemnation that our witnesses have in fact traveled outside San Juan County, so be it. We think it's a positive benefit and that they haven't been subjected to the blinders of having one year experience repeated twenty-five times over the course of history.

The good faith and serious nature of Mallon-Mesa Grande is further demonstrated by the fact that they selected as competitors who have been in dispute before this Commission on this various pool, to select an independent third party in whom they had confidence to tell them the real facts.

The acreage position and the producing position of both these companies clearly demonstrate their major commitment to this pool. There are no two operators that want a bigger bang for their buck and it is in this vein and in this sense that they presented their testimony here today.

What we've heard from McHugh and Greer is what at best can be characterized as a misguided attempt to compare apples and oranges.

At worst it is a thinly disguised attempt to intimidate the other working interest owners in the pool into a unit of their making while at the same time allowing McHugh to capture the reserves of offset operators in the pool because of his position and because of the history of the production of his wells, as well as providing an opportunity for Mr. Greer to continue his traditional posture of not drilling any wells and of claiming that one well will drain the entire San Juan Basin.

The evidence that we have that we are comparing apples and oranges, and that the West Puerto Chiquito is different and not applicable to the Gavilan-Mancos Pool, is first demonstrated by the fact that after twenty-five years of drawdown in the Puerto Chiquito, and after the production of millions and millions of barrels of oil, we only have 80 pounds difference in initial reservoir pressures between the Puerto Chiquito and the Gavilan-Mancos.

In addition, this separation is further supported by the fact that the interference test performed on the Dugan-Greer wells up in the northwest, or the northeast portion of the Gavilan-Mancos Pool, across the unit boundary, experienced immediate interference within a matter of hours.

There is further support for the separation by the fact that Mr. Emmendorfer's testimony demonstrated that both horizons above and below the Gavilan-Mancos experienced different geological characteristics and pinch-out at the area of the permeability barrier.

The real similarity between the

two pools is that it's a highly fractured, both of them are highly fractured reservoirs. At least this is what we initially heard from Mr. Greer as of two weeks ago.

If I understood the testimony of Mr. Roe and Mr. Greer at that time, we were all in agreement that the Gavilan-Mancos, as well as the Puerto Chiquito, were one great, big barrel with communication throughout the horizon.

Now we've heard contradictory testimony today that we have stratified horizons in the Gavilan-Mancos. I don't know what their true position is. The record currently reflects that they've taken both sides of the issue.

I don't think it would gain us anything to re-examine all the engineering testimony that you have heard today. It is clear that the two camps have diametrically opposed views.

The thinly disguised attempts of the Greer-McHugh camp to intimidate other working interest owners into a unit simply won't fly. We're pretty mcuh divided 50/50. In order to get statutory unitization it's going ot take at least 75 percent volunteer joinder and that can't be reached.

The Greer camp suggested that the 1,200 barrel a day ratio should only be temporary for ninety days until unitization were accomplished. If we were all in agreement, I seriously doubt that unitization could be accomplished within ninety days of today's date.

The only true issues before the Commission are the issues of correlative rights and the prevention of waste.

Let's take the first -- or the last first, with respect to the prevention of waste.

There has been no evidence, in fact without re-arguing it, I would say the evidence is convincing that from the position of Mobil and clearly from the position of Mallon-Mesa Grande, that there will be no gain or loss to ultimate recovery in the pool if you restrict or don't restrict production. I'll let the testimony and the record speak for itself.

The only -- the basis, only basis on which Mr. Greer claims waste will occur is due to down dip drainage, or gravity drainage. I think the evidence has been ample that the difference between the degree of slope of the Puerto Chiquito and the Gavilan-Mancos indicates that the Gavilan-Mancos will not experience the kind of vertical drainage recovery that Mr. Greer has enjoyed over the last twenty-five years, but assuming for purposes of argument that there is something to what he says, we move on to the issue of correlative rights.

His position would be a clear violation of other working interest owners correlative rights because the evidence is uncontroverted that the McHugh wells lie on the down dip slope, have enjoyed the greatest production historically in the pool, and have the greatest presssure drawdowns; consequently, this thinly disguised attempt is no more than an effort to severely restrict production so his portion of the pool can be repressured and any oil that might otherwise be drained by others, according to the rules of the Commission, would migrate towards their leases, clearly in violation of the other parties' correlative rights.

My final point would be that if the Commission were to adopt any other recommendation than the one that we've suggested, which we feel is a conservative and rational approach, and one that is clearly between totally contrary views as to how to produce the reservoir, that the effect, or if you were adopt the McHugh-Greer approach, that it would indeed affect the drilling of additional wells, especially at a time, which the Commission can recognize, may be the time that we will enjoy the highest price for the product, because historically, after January the prices drop, and that in fact the result will be that the ultimate recovery will be affected because prudent operators will not be allowed to develop the pool on a consistent and rational spacing pattern so that it can be -- so that the production can be fully realized.

My final comment would be to call your attention to the last Dugan Exhibit Four and point out that the only scenario under which the effect of restricted production on the operators in the -- the major operators in the pool that would have less than two percent variance between operators, would be the proposal that the Mallon-Mesa Grande group has put forth, namely, the -- or close to it, it's 588 GOR; we selected 646, with the current oil allowable remaining at 702.

That has the most even effect across the operators as their exhibit shows. Any other exhibit would have a greater impact adversely on the Mallon-Mesa Grande group and a commensurate advantage to the Greer-McHugh group.

I'm sure my other cohorts will have other things to add but I think that fairly well summarizes our position.

MR. STAMETS: If your other cohorts have about five minutes apiece that they'd like to add at this point, we would provide that opportunity.

MR. PADILLA: Mr. Chairman, Members of the Commission, Mr. Kelley, this is a very important case just by the cross section of audience that has been here during the course of this hearing.

We have had producers. We have had royalty owners. We have had refining companies and obviously the parties involved in this case who have contested the application vigorously.

We are comparing in this case the West Puerto Chiquito and the Canada Ojitos type of production with a competitive basis. Probably it is too late at this point to even attempt to compare those.

We have a number of producing wells in the Canada Ojitos Unit that on the relative basis produce a lot of oil. The mechanisms for recovery of the oil are two entirely different things.

If we go and say that an analogy of apples and oranges is incorrect. It's more an analogy of apples and a brick.

With respect to the nature of the emergency, I was working on what I was going to say today last night and I looked at Webster's definition of emergency. That definition is that it's -- refers to any sudden or unforeseen situation that requires immediate action.

A synonym for emergency is crisis, another word that has been used around here by the applicants in this case. It refers to an event regarded as a turning point which will decisively determine an outcome.

Now, we have had two sides present testimony here. On Friday the chairman pointed out that both sides had done an equally good job and I don't see anything decisive about the application and the case presented by the applicants in this case. The true nature of what's going on here is that you have, especially in the McHugh application, they have at least twenty-eight wells or in that order, which have cumulative production of 1.3-million barrels.

At the same time they're trying to restrict the allowable and at the same time severely and -- penalize the production that can be obtained from the Mallon wells, in which Koch Exploration has its working interest.

So what we really have here is that on the Greer side Mr. Greer, obviously, doesn't want to drill any wells because it's not within the contemplation of the operation of his unit.

On the competitive side, on the Gavilan Unit, you simply are bound by the current regulations on spacing. It's must a matter of producing that and there has been on compelling testimony here one way or the other that the emergency exists and that we should be bound by what the applicants say, other than the fact that this morning we have reduced the scale, I guess, from a reservoir in an emergency or crisis situation to a reservir in trouble.

As I view that, it seems like it's a down -- it no longer is an emergency situation, presumably based upon the presentation that was made by Mr. Hueni.

As far as a compromise is concerned, we have presented evidence here that in the nature of a compromise, to try to get some kind of a study that has been going on. Now, as I understand this compromise, we may have compromised ourselves away. As I see this thing, we have through the course of this hearing seen only the cartoon and the main feature is to be presented later by the applicants.

I'd venture to say that there are going to be further proceedings regarding this development of the Gavilan-Mancos Pool and I think we have made objections regarding testimony that was presented regarding units and with regard to spacing.

Certainly acreage has been totally ignored in this case. Twenty-eight wells and twenty-eight proration units, maybe with one exception. Acreage is important and I think that the Continental Oil case versus the Oil Conservation Commission has not been followed and I understand you have to determine total reserves as reasonably as can be done, or as practically as can be done, but I think that that has been totally ignored and that has been missing. You're simply taking some kind of a new formula and it's not followed any case authority for any equitable method of allocating production in accordance with the conservation laws that have been (inaudible) by the Commission.

Thank you.

MR. STAMETS: Thank you, Mr. Padilla.

MR. PEARCE: Thank you, Mr. Chairman.

Following along the line of my witnesses to this proceeding, I'll try to move swiftly. I think that's for the benefit of everybody here, but let's see.

What I want to do in the next couple of minutes is try to bring this thing back down out of what I consider the ether. We've got conflicting petroleum engineering opinions. We've got more data floating around this room than we can possibly analyze and frankly I'm not sure we know what to do with it.

I want to bring us back down to where I think we're supposed to be in this proceeding.

We're here today because Jerome McHugh filed an application for a lower limiting gas/oil ratio and lower production allowables for the Gavilan-Mancos Pool.

Now this case was consolidated with the case from the West Puerto Chiquito Mancos Pool but the applicant in that case has said he doesn't want to be here by himself and if you don't grant Mr. McHugh's application, he don't want you to grant his.

For that reason I'm not going to pay any attention to the West Puerto Chiquito because it hasn't got anything to do with what's going on here. He's talking about some possible future boundary agreement between the two pools. That's far enough down the road that I'm not going to worry about that. I don't think we have to worry about that in this room today.

What we've got to worry about today is Mr. McHugh's application, and when we started this hearing five hearing days ago, and a couple of weeks, counsel for Mr. McHugh said that we have a state of emergency and he said that he'd show that the pool was in the midst of a dramatic, irreversible, reservoir-wide pressure decline and production changes. He said that he'd show that the accelerated pressure declines and the increasing dissipation of reservoir energy are resulting in waste.

Now, Mr. McHugh filed this application and by filing that application Mr. McHugh took the burden upon himself. I don't think the record shows that he's met that burden and in the absence of him meeting that burden, I don't think you can grant his application and I don't see any need to compromise on an application that ought to be denied. I don't think that's fair.

This pool is operating under statewide rules and those rules were themselves a compromise, I think. I think history will show that if the Division did not know specifically what should be done, the determined statewide rules ought to apply.

I don't think the Division or anybody in this room knows what ought to be done and I think the statewide rules ought to apply. I think that's why we have statewide rules.

Let's look at what Mr. McHugh has shown us so far.

The first witness to this proceeding, outside of a landman, I guess, the second witness, was Mr. McHugh's own geologist.

Mr. McHugh's geologist testified that the developed area of this pool showed what he called very low relief. All the structure maps that we've seen in this proceeding so far confirm that. Maybe a thin pancake up there on top, but it's flat.

The same McHugh expert witness

concluded that this was a solution gas drive reservoir. That's what he said it was.

Mr. Roe, the petroleum engineer who's primarily responsible for the applicant's operation in this area agreed with that. He said, and I quote: We indicated that solution gas drive is our primary production mechanism.

Further on he said, the fact that GOR is increasing is something that is predictable and we should expect in a solution gas drive reservoir.

Mr. Roe plotted some Gavilan production data dealing with pressures and GORs on a graph which have been around for a long, long time, and we all showed you that graph. It was that infamous orange piece of paper and it looked like that, and Mr. Roe said, that if you exclude the early production when he thought this pool was producing above the bubble point, if you excluded that data, that he suspected that pressures and GORs in this pool would match the predicted solution gas drive curves, which are in his exhibit.

That graph indicates that ultimate recovery from a solution gas drive reservoir is not rate dependent. I asked him the question and he answered the question. He said, no, if it's solution gas drive it doesn't matter whether you take it out quickly or you take it out slowly, you don't get any more oil.

Mr. Chairman, if the reservoir is performing as you would expect it to perform, and if the pressures and the GORs are matching the predicted curves for those two sets of data, and if the ultimate recovery is not increased by reducing the rate of production, I don't understand what the emergency is out here.

(Interrupted by turning tape) primarily a solution gas drive reservoir, there may be a gravity production mechanism which needs to be utilized.

Let me just hang this up for a minute so I can talk about it and maybe it will speed me up, Mr. Chairman.

This is -- this happens to be Mobil's structure map. It's not all that different from other folks structure maps. The testimony, Mr. Chairman, indicated that the flattest part of the West Puerto Chiquito Pool is twice as steep as the steepest part of the Gavilan Pool and therefore gravity is a factor in the Gavilan Pool.

Now I didn't follow that logic, since their own geologist indicated that it was an area of very low relief, but if you look at the pool, Mr. Chairman, what you find is that there are only two sections which are going to benefit from gravity drainage, if there is any, Sections 20 and 29 of 25 North, 2 West. Both those are

McHugh tracts.

To the west of that are two short sections in which Mr. McHugh, the applicant in this matter, has proposed well locations.

We've also had the indication during this case, Mr. Chairman, that these is a possibility of secondary gas cap recovery mechanism. We don't see the type of structures which would lend themselves to that mechanism.

In addition, the geologist for Mr. McHugh testified that high GORs seem to be related primarily to areas of higher production rather than structure.

In contrast to this gravity structure theory bouncing back and forth across the table, one party to this case has presented you with core data which indicates that the matrix will contribute production in this reservoir. That core analysis has been backed up by properly done log analysis.

Mr. Chairman, it's right, if you let the matrix produce in a field, it will produce, and once again, that matrix production is not rate sensitive. The matrix will give up that oil slowly or quickly, and I don't think it is waste to let that matrix give it's oil up more quickly. It's not going to give up more oil if you slow it down. It's just going to make everybody wait longer.

Finally, Mr. Chairman, I feel compelled to express my concern about some of the testimony that's gone on in this case.

Mr. McHugh's geologist took the stand and he testified, and I'm quoting him, Mr. Chairman, if we are not prepared at the end of this proposed ninety day temporary rule to make application for a Gavilan unit, then we will be back for a further reduction in production rates at that time.

Mr. Chairman, that has an ominous ring to us and we don't like it. This Commission is not authorized by the Legislature to force anybody into a unit for primary recovery. There are very limited circumstances when this Commission can force anybody into a unit for secondary or terciary recovery, and we are concerned what we have here is an application that tries to get the Commission to help the applicant do indirectly what the Commission itself cannot do directly, and that's force people to join a unit to save their businesses.

This morning I sat down and I looked through Mr. Roe's Exhibit Number Three, Dugan Exhibit Number Three, which had the cumulative productions, and as has been pointed out to you a couple of times in the last couple of minutes, Mr. McHugh's wells so far have produced more than a 1,300,000 barrels of oil. Mr. McHugh has twenty-three wells out here and he's indicated during his testimony that those wells cost about $500,000 a well.

If you take into consideration the gas production that he's had with that oil production, I think Mr. McHugh's got payout on his wells. He doesn't have any money on the table. He can afford to reduce his income string for as long as it takes to force everybody into a unit because he's got payout. That's not the case for other operators in this pool, Mr. Chairman.

We're extremely concerned. We don't have wells that have been a long time and we've got a lot of money on the table right now and if you reduce allowables and you reduce production, we can't earn return on that money.

During his testimony this morning Mr. Greer indicated that there was in his opinion a normal human tendency to accept the things that support your initial conclusion. It seems to me that we've got some of that going on from the applicant in this matter. I'm afraid the applicant has concluded that he needs to reduce allowables in order to enhance the recovery from his already partially depleted wells. The operators and owners of other tracts in this pool have come to a radically different conclusion.

For these reasons, Mr. Chairman, Mobil asks that the application of Jerome P. McHugh to lower the limiting gas/oil ratios and lower the allowables in this pool be denied so that other operators in this pool who have not been the beneficiaries of long, high production, be allowed to drill the wells that are necessary, necessary wells for them to recover their fair share of reserves by utilizing their fair share of this reservoir's energy.

Thank you, Mr. Chairman.

MR. KELLAHIN: Mr. Chairman, I'll be the first one to tell you that most of the cases we do over here are routine, garden-variety cases that I venture to say both you and I forget after we do them. We've done it over again.

But occasionally, every five or six years, a case coms along and grabs everyone's attention and gives the Commission the unique opportunity to exercise its discretion and make a permanent contribution to oil and gas conservation. This is one of those kinds of cases.

We think that you do not have to decide right and wrong in this case. You don't have to be an engineer, a geologist, or any technical person, to resolve this case. We hav abundant quantities of all those kinds of people that can talk ad infinitum about what to do with this reservoir.

What we need is some wisdom and some common sense from you gentlemen to help us out of this predicament. It's one we are creating for ourselves and you can see by the polarization of the parties in this case you must intervene or serious consequences will occur to this reservoir.

Mr. Padilla indicated that there was no Oil Conservation concept that was involved in this. This case is a bedrock of conservation; it's a question of waste. It has nothing to do with economics. If we could resolve the economic issue we'd have done that among ourselves.

The waste question is one you need to address and help us resolve and it's simply whether or not this pool is being operated in such a way that it's inefficient, excessive, and improper. That's the very first sentence out of your book.

It's not very often you get a case squarely on that issue. Why don't you need to decide right and wrong? Because what you need to do is write the next chapter of what may be a very long book.

The first chapter was the spacing case where the Commission agreed several years ago to 320-acre spacing on a temporary basis.

This is the next chapter in the story and it's a chapter based upon whether or not we take and seize the fading opportunity to get gravity drainage recovery out of this reservoir or forever lose that chance. Depending upon how you write that chapter we're either going to have a tragic example on how to mismanage a reservoir or a textbook case on how the Commission ought to conduct its affairs.

I said awhile ago you don't have to be an engineer or a geologist to figure out how to handle this case and I sincerely believe that. I've sat here for as many days as you have listening to testimony that I couldn't comprehend; I haven't a clue as to what some of these guys are talking about, but I don't think you have to understand that in order to break the polarization of the parties. This is not a one time case. It's a temporary solution to give us a time so that these fine technical people can help us resolve the issue of how to produce this reservoir.

I think there's only two things that you have to do. One is come up with a solution that compells the working interest owners to resolve their own problem in this reservoir.

The second thing is you must take sufficient action to prevent waste and conserve the reservoir energy in this pool.

What position will you don? It's not the classic one where you can take each extreme, cut it down the middle somewhere in a compromise and think you've solved the problem. We've got a stalemate now. I suggest to you that if you adopt Mesa Grande-Mallon approach, that just perpetuates the stalemate and we're no farther along tomorrow than we are today.

Let's examine the position of the various parties in the case.

Mobil's got an interesting position. They've got two wells that produce in this pool. They come in here and say, "There's nothing wrong, looks fine to me. Got a lot of matrix production down there, we're going to suck it out and draw that pressure right down." Wouldn't that be great? We'd love it if they're right.

But what if they're wrong? What if you don't take action and they turn out to be wrong? We've blown our chance to get what Mr. Greer and Mr. Roe have said they think will occur in this reservoir, the impact of gravity drainage.

Mobil's not alone on that position. Koch, Mesa Grande, and Mallon, as well as McHugh and Greer, all realize something must be done. It's a question of degree. Mesa Grande and Mallon have suggested that in order to effectively produce the reservoir we must reduce the gas/oil ratio, if nothing else; bring that down to the solution gas/oil ratio, and then Mr. Hueni says everything works just fine.

That's great. What if Mr. Hueni's wrong? We've missed the chance to get the gravity drainage that Mr. Greer has experienced and established for you in the Canada Ojitos Unit, which he says will occur in the Gavilan-Mancos.

We need to seize upon that opportunity. In order to do that, I'm intrigues with Mr. Kelley's suggestion several days ago. I think he said why don't we just shut the whole thing in. That would get somebody's attention.

Maybe that is the approach except it's too extreme because that kind of drastic action will solve the first problem. It will get everybody to some kind of solution within the ninety day period, which is a small window to try to resolve the tremendous disparity of opinions you have here today, but it's going to take drastic action to get to that point.

How do we solve both of the solutions? Mr. Kelley's suggestion of shutting in the whole reservoir will accomplish one. It gets everyone's attention, but we contend it would be wasteful and it would violate correlative rights.

We've got to have a minimum producing rate in this reservoir that continues to let the operators recover some income source from this reservoir. We suggest that the level of voidage Mr. Roe has spent weeks and months examining is the level that ought to be adopted and it's the one that restores this reservoir to the producing rates in April prior to the drastic effects that he's testified to that we are seeing with the June and July produciton and the gas/oil ratios. They're going right out the (unclear). Everything we said to you back on June 7th has been supported by the testimony of our witnesses.

We think that's the solution; it's drastic. It's going to get the economic attention of the operators. It's what we have to have. It avoids potentially the stalemate and allows you, then, not to have to decide who's right or wrong about how the pool operates. You've taken the most conservative action available to you in order to give that mechanism of gravity drainage an opportunity to be further examined by these fine technical people.

As we went along I thought of all kinds of cute and clever things I thought were interesting and I've forgotten most of them. The one thing I think has made the biggest impression upon me in the last five days of hearing is Mr. Greer's testimony with regards to the effect of each day's delay in action in reducing the levels of withdrawal in the reservoir.

Mr. Roe has told us there is no loss of production; we're simply postponing it until some later date, but Mr. Greer has told us that at the rate of $150,000 a day we are losing the opportunity to take advantage of the gravity drainage.

This hearing started on August 7th. It is now August 27th and we've just thrown away $3,000,000.

MR. CARR: May it please the Commission, Benson-Montin-Greer Drilling Corporation is here before you today because we have an interest in the Mancos formation in the area which is the subject of these consolidated cases. This is a common resevoir. There's communication in varying degrees throughout the reservoir, and we have wells on both sides of the permeability restriction which runs across the subject area.

We're also here today because we have a problem with that reservoir. I don't want to be now accused of downgrading emergency to trouble to problem, but we have a problem because the reservoir is in trouble and it is in trouble because we have an emergency situation and we're here today because the operators in the pool cannot agree as to what must be done right now to deal with that problem, and so we come before you and we're presenting to you what is certainly a complex question. In doing this we are not looking for Solomon to come and split this for us. We're not asking somebody to give everybody a little something. We're asking for a decision that is based squarely and soundly on the statutory duty imposed on each of you by the New Mexico Oil and Gas Act.

This Commission is a creature of statute. Your powers are expressly defined and limited by the Oil and Gas Act and it is your duty to take what actions must be taken to prevent waste and to protect correlative rights.

If you are to carry out your duty in this case in view of the evidence presented, we submit you have no alternative but to act, to act now, to take meaningful action, action that will effectively address the problem which is clearly before you. A half decision, a compromise which merely reduces gas/oil ratios, is no decision at all. It leaves us with the same problem. It leaves us with no solution in the foreseeable future and it really gives no one here any incentive to get together and try and work this problem out.

We submit you must act immediately. You must limit production in the Gavilan-Mancos and the West Puerto Chiquito Mancos Pools. You need to limit to the 200 barrels a day per 320-acre unit and you need to set a gas/oil ratio of 1000-to-1 for a ninety day period, and if you do, it is our hope that the operators can get together and that real progress can be made towards solving the problem which is before you.

Now the evidence presented in this case has been extensive; it's probably better to characterize it as exhaustive, but I think any characterization of the evidence shows that we probably have excessive withdrawal rates in the Gavilan; that we have potential reservoir problems unless action is taken, unless it's taken now. If no such action is taken underground waste will occur.

We have evidence that excessive -- an excessive number of wells will have to be drilled in the area. This is surface waste, and the evidence shows that correlative rights in the area will be impaired unless action is taken.

If you take action, if we can work out something that will enable us to efficiently produce the reservoir, then all operators in the pool are afforded an opportunity to produce their just and fair share of those reserves.

If no action is taken and we are right and permanent reservoir damage occurs, then everyone's correlative rights are impaired.

Now those who are in opposition to this application would say, well, we're going to lose all this revenue. That's not true. That is simply not true. The revenue will be deferred and all we're seeking is that that be deferred and those reserves will be there and those reserves can be made up at a later time.

You have basically two solutions being proposed, one by Mr. Hueni for Mesa Grande and Mallon; one by Mr. Greer for Dugan, McHugh, and Benson-Montin-Greer.

Now what are we really looking at? We are looking at four weeks work, compared to the work of more than a quarter of a century.

We're looking at the work and the testimony of a man who's spent a large portion of his life studying and developing this area, and we contrast that testimony with a man who's hired to tear this work down.

Mr. Greer's testimony, we submit to you, is accurate and the reasons it's accurate, the reason it is accurate, is that it was not developed for the purposes of this hearing. It was developed so he could operate effectively the Canada Ojitos Unit. It was developed, it was used, and whether it is one lesson that took twenty-five years to learn or twenty-five one year lessons it's been proven right and his testimony is right.

Mr. Hueni's data and conclusions are based on information which is inaccurate and incomplete.

If you accept Mr. Greer's position and he is right, we submit you will have carried out your statutory duty.

If you accept Mr. Greer's position and he's wrong, some income will be deferred, but the reserves will still be there.

If on the other hand you want to accept Mr. Hueni's testimony and he is wrong, the only thing you will have done, and it will come back to you, you will have authorized waste and you will have impaired the correlative rights of every single operator in that area in that formation.

Yes, you're being asked to decide a complicated question but we submit it isn't difficult. What we're asking you to do is limit production, limit withdrawals for a ninety-day period, and we submit what we are asking you to do is consistent, based on this record, with what the New Mexico Oil and Gas Act directs you to do.

MR. STAMETS: Thank you, Mr. Carr.

(Thereupon a recess was taken.)

REPORTER'S NOTE: The following is the decision of the Commission as announced by Chairman Richard L. Stamets following the conclusion of presentation of testimony on Wednesday, 27 August, 1986.

MR. STAMETS: First of all let me begin by saying that this is probably the most difficult case that I have seen in many, many years. Also the overall quality of the testimony I thought was excellent on both sides, which is one of those things that makes it extremely difficult to render a decision in this case.

I would personally like to grant everybody's request, everybody's position; however, that cannot be. Perhaps Amoco said it best when they said that if we must err, there's always the opportunity to err, that we must err on the side of prevention of waste.

When we look at the evidence in this case, we believe that the preponderance of the evidence indicates that there will be some benefit to the reservoir from the gas which disassociates itself from the oil. We believe that McHugh, et al, indicated that might be from a major gas cap.

Mallon-Mesa Grande indicated that might be a gas cap on each individual well.

Nevertheless, to allow that gas

to be dissipated without doing its work certainly would waste reservoir energy.

Therefore we will reduce the gas/oil ratio, limiting gas/oil ratio in this pool as of September 1, beginning the proration period, the proration period beginning September 1, to 600 cubic feet a barrel.

As to the oil allowable, that is a much more complex issue.

702 barrels a day which applies currently in this pool is no magic number. This is certainly a number which would represent what an average pool in the state at that depth with that spacing should have.

At this point there seems little doubt that this is not an average reservoir. There is apparently little or no matrix participation in this reservoir; certainly not compared to the average sandstone reservoir or the average limestone reservoir.

There would seem to be less oil in each unit of reservoir in a fractured shale, in this fractured shale reservoir than you would expect under a similar sandstone or limestone reservoir.

We believe that there is a strong potential for gravity drainage to work in this reservoir.

There are equity problems, as well. Obviously McHugh's wells have been in this reservoir for some period of time. He has enjoyed the drainage.

Those who have recently completed would like to enjoy that same amount of drainage.

Nevertheless, the spectre of waste is quite clear in this pool.

We've had recommended a production level of 200 barrels a day. While this may serve to prevent waste, if the gravity drainage is as strong a factor as some of the testimony in this case would indicate, that does not address the situation of an operator who has only recently completed his well based upon the anticipated production which he will get from that well.

Therefore the Commission will for the short term adopt the lower allowable of 400 barrels per day, an allowable which we may reduce at a later time, or an allowable which we might increase at a later time.

We are most impressed by the engineering testimony on both sides. We would desire to see those people testify for the same ends the next time this comes before the Commission.

We would encourage everybody to try and arrive at a position which everyone can support. We believe that at any future hearing we must have much clearer evidence about gravity drainage in the Gavilan Pool. We must have much clearer evidence as to what -- how much oil is there in the unit or reservoir and how do each of the units relate to one another.

We would ask that the attorneys for McHugh and Greer supply us with a draft order which will have the appropriate findings and ordering paragraphs in conformance with the decision that we have announced here today, and which will go into effect at the beginning of the proration day, September 1, 1986.

I'd like to have that order by no later than a week from Friday morning.

MR. PEARCE: Excuse me, is it your intention to have this order in effect until it is changed or is there some time limit on this order?

MR. STAMETS: The application was for ninety days.

MR. KELLAHIN: Mr. Chairman, it said not less than ninety days.

MR. STAMETS: Not less than ninety days, thank you, Mr. Kellahin. Ninety days from September 1 is December 1, isn't that correct?

MR. LYON: Right.

MR. STAMETS: Not a very good time to have a hearing.

January? New legislature in session? Not a very good time to have a hearing.

They don't go home till March the 15th.

I don't really see a good time to have a hearing. What -- what my choice to do would be to have these in effect until further order of the Commission but to have a report from the committee and preferably a come in to Santa Fe and sit down with the staff, by about the middle of November, and let's see what kind of progress has been made at that time, and we will determine whether or not we should reopen this case again early in December, and attempt to take some additional action before the -- before January, 1987.

Any other questions?

If there is nothing further, I want to thank each of the participants and I look forward to seeing you again in a few months.

(Hearing concluded.)

C E R T I F I C A T E

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY that the foregoing Transcript of Hearing before the Oil Conservation Division (Commission) was reported by me; that the said transcript is a full, true, and correct record of the hearing prepared by me to the best of my ability.

Sally W. Boyd CSR