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

16 June 1988

COMMISSION HEARING

VOLUME IV OF V VOLUMES

IN THE MATTER OF;

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

CASES 7980, 8946, 8950, 9111, 9412.

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

TRANSCRIPT OF HEARING

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(Thereafter at 8:30 o'clock a. m. on the 16th day of June 1988 the hearing was reconvened and the following proceedings were had, to-wit:)

MR. LEMAY: The hearing will come to order. Let's get this show on the road.

Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Chairman. We'd like to call as our next witness, Mr. John Roe.

Mr. Roe's exhibits were circulated on Monday. They are the exhibits in the legal size manila folder.

JOHN D. ROE,

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Roe, for the record would you please state your name and occupation?

A My name is John Dale Roe, Junior, and

I'm a petroleum engineer for Dugan Production.

Q Mr. Roe, are you a Registered Professional Engineer?

A Yes, sir.

Q And you registered by testing, did you, sir?

A Yes, I have.

Q Have you as a Registered Professional Petroleum Engineer studied the Gavilan Mancos production since Northwest Pipeline completed the Gavilan No. 1 Well in March of 1982 as the discovery well in the Gavilan Mancos Pool?

A Yes, I have.

Q And were you an expert witness in the Commission hearings in November of 1983 to consider the establishment of temporary rules for that pool?

A Yes, I was.

Q And were you an expert witness in the August, 1986, Commission hearings concerning those rules?

A Yes.

Q And were you an expert witness in the March and April, 1987, hearings again concerning making those rules permanent?

A Yes.

Q Have you testified concerning the

boundary issue between Gavilan Mancos and the West Lindrith Pool before the Commission in the fall of last year?

A Yes, sir.

Q And did you participate in the work -- working interest owners' study groups concerning the Gavilan Mancos Pool?

A Yes, I did.

Q And have you obtained the data from the bottom hole pressure test and production tests there were conducted from June of '87 through February of '88?

A Yes, I have.

Q And have you analyzed that data?

A Yes.

MR. KELLAHIN: Mr. Chairman, we tender Mr. Roe as an expert petroleum engineer.

MR. LEMAY: His qualifications are acceptable.

Q Mr. Roe, in making your study have you reviewed the issues the Commission has put on the docket of notice for hearing, where they have set forth seven -- some five categories of issues for consideration and discussion? Are you familiar with those issues?

A Yes, I am.

Q And have you formulated, based upon your study, opinions as to all of those issues?

A Yes, I have.

Q Let's go back to November of '83. What occurred as a result of the Commission hearings in November of 1983 insofar as Gavilan Mancos is concerned?

A Would you repeat your question, please?

Q In November of '83 the Commission did what with regards to the special rules for the Gavilan Mancos Pool?

A The Commission established initial pool rules for a temporary period of three years and they set the initial spacing for development at 320 acres and --

Q What were the temporary producing and gas/oil ratios established by that hearing in November of 1983?

A The Commission set the allowable during the temporary pool rules at 702 barrels of oil per day for a 320-acre spacing unit and they adopted the statewide GOR ratio limitation of 2000-to-1.

Q In looking at the issues the Commission has asked us to address, Mr Roe, do you have an opinion on whether the Gavilan Mancos Pool and the West Puerto Chiquito Mancos Pool are producing from one common source of supply?

A Yes, I do.

Q And what is that opinion?

A It is my opinion that the pools produce from a common source of supply and are in communication with each other.

Q In dealing with your study and involvement of the Gavilan Mancos production, as well as the production from the West Puerto Chiquito Mancos, have you seen operationally whether or not you can separate the two pools using the current boundary between pools based upon the production being in either the A, B, C zone or some combination?

A No, we haven't observed any difference in productivities throughout the Niobrara member that would help us break the West Puerto Chiquito and Gavilan Pools into separate areas.

Q Let's talk about the current boundary between the two pools, Mr. Roe.

Do you have an opinion, Mr. Roe, about whether the current boundary between the two pools can be moved two rows of sections to the east?

A Well, it can be but its no -- no reason to move it. There's no geologic or engineering basis for moving it two sections to the east.

Q What, to your knowledge, has occurred along the current boundary between the two pools that would give you a basis of support for allowing that boundary to remain where it is?

A The primary reason for the -- my feeling the boundary should remain where it's at was we -- we initially felt that there should be no boundary between the pools; that back in the 1987 issue of making the temporary pool rules permanent it was our proposal to abolish one or the other. We chose to abolish Gavilan and extend West Puerto Chiquito, but we could just as easily have abolished West Puerto Chiquito and extended Gavilan. We felt the pool, both pools, should be governed basically under the same set of pool rules; however, that did not occur and the boundary was left basically the line between Range 2 and Range 1 West. And because that was the established boundary between the pools and primarily because of the pressure maintenance in the West Puerto Chiquito Pool of the Canada Ojitos Unit, and the lack of a unit in Gavilan, there has been a significant development effort along that line to basically protect, as best we can with offsetting production, unitized substances of the Canada Ojitos Unit against the non-unitized area in the Gavilan.

Q Let me direct your attention, Mr. Roe, to what is marked as Dugan Exhibit Number One. Would you hold that up so that we can all find what you have marked as your Exhibit Number One?

A That would be kind of a reddish brown

colored bound set of statistical information.

Q Would you identify for us what is contained in that bound volume, Mr. Roe?

A Okay. Exhibit One is -- is basically nothing more than an update of production statistics for the Gavilan Mancos Pool. The data is presented in three or four different manners.

In the green pages it's presented as a pool total from date of first production from the pool and it takes the production through March of 1988.

The pages that are shaded pink basically gives the same information except it gives you totals by operator.

And then the pages that are a white is the individual well statistical data from date of first production through March of 1988.

Q The production statistics for the Gavilan Mancos Pool will include the high and low rate test periods?

A Yes, that is correct.

MR. KELLAHIN: Mr. Chairman, we move the introduction of Dugan Exhibit Number One.

MR. LEMAY: Without objection, Exhibit One into the record.

Q Mr. Roe, let me direct your attention

now to Dugan Exhibit Number Two. Would you hold that book up so that we can all see which one it is?

A Okay, that's the, basically similarly bound, but it's with the -- covered with the blue cover. It's titled West Puerto Chiquito Production Statistics.

Q And what have you compiled when you put that volume together, Mr. Roe?

A It's pretty much the same information; however, it is for the wells in the West Puerto Chiquito Mancos Pool.

In the green pages we pretty much present the pool total production.

The pages that are shaded in pink is the field with just the Canada Ojitos Unit.

And the pages in blue deal with wells that are within the Puerto Chiquito Mancos Pool but outside the Canada Ojitos Unit, and specifically that's the four wells that would be to the north of the unit operated by BMG.

The one thing that might be particularly useful is that Mr. Greer has a practice of referring to wells by their unit letter and section; in other words, A-20 is a well that he commonly refers to; however, the Commission records would reflect that that's Unit Well No. 36, and so the gold page in this book has a cross reference between unit well number and unit letter section -- it actually identifies the location of the well.

On the white pages it would be the individual production statistics for each well within the West Puerto Chiquito Mancos Pool.

Q And for what period of time do those production statistics cover?

A The statistics cover all production from the well. In both Exhibit One and Exhibit Two this is the production records that were filed with the Commission on State Form C-115.

The data in the Exhibit Two actually goes through April of 1988.

Q The data in Exhibit Number Two includes, then, the high and the low rate production periods?

A Yes, it does.

MR. KELLAHIN: Mr. Chairman, at this time we move the introduction of Dugan Exhibit Number Two.

MR. LEMAY: Exhibit Two into the record without objection.

Q Mr. Roe, one of the issues the Commission asked that it be studied and addressed was Issue Number 3 on the docket sheet when it talks about an analysis and interpretation of the results of the June 27th, '87, to

February 19th, '88, production and bottom hole pressure testing.

Have you reviewed that information and have you made an analysis and interpretation of those results?

A Yes, I have reviewed the information and have interpreted and have those results.

Q Let me focus on the high rate production test period. Would you identify for us what the dates are that cover that test period?

A Yes. The high rate of production test period that we've all referred to was the initial production phase of the test that the Commission ordered in Order R-7407E and a companion Order R-6469D, that dealt with the West Puerto Chiquito Pool Area.

The initial production phase began July 1st of 1987 and ended on November 16th of 1987.

Q How many days did that test cover?

A It covered 138-day period or approximately 4-1/2 months.

Q In round numbers, Mr. Roe, what was the total gas produced during that test period?

A The total gas produced during that period was 2. -- nearly 2.2 billion cubic feet.

Q And what was the total oil produced?

A 443,200 barrels of oil.
Q And what did you observe in terms of pounds of pressure loss per month during the test period?
A Okay. During this 4-1/2 month test period we averaged approximately 203 pounds -- or the average pressure loss throughout the duration of the test was 203 pounds.
Q And on a monthly average, what is that, sir?
A That relates to approximately 45 pounds a month, given that we were covering a 4-1/2 month period.
Q In analyzing the data with regards to those numbers, did you include within those production numbers wells other than the Gavilan Mancos Pool wells?
A No, that pretty much just reflects the production within the Gavilan Mancos Pool.
Q And when we talk about the Gavilan Mancos Pool, we are talking about that area exclusive of the expansion area which lies in the West Puerto Chiquito Mancos Pool.
A Yes. We -- all references that we will make to the Gavilan Mancos are pretty much as the Commission records reflect the Gavilan Mancos Pool to be.
Q At such instances that you deviate from that basis you will let us know that you've included some-

thing else?

A Yes, and at any time if I ever include anything else I'll let you know.

Q During the high rate test period, Mr. Roe, what were the maximum allowables allowed on a 320-acre spaced unit?

A During the period July through mid-November, a 320-acre spacing unit was permitted to produce 640 barrels of oil per day and 1280 MCF of gas per day.

Q Is there a corresponding statewide allowable for a depth bracket for wells at this depth that use either a 320-acre or 640-acre spacing?

A There is not.

Q And what specific rule are you referring to?

A Well, the statewide rule that actually sets forth the depth bracket allowable is Rule 505.

Q And stops at 160-acre spacing?

A That's correct.

Q When we look at the low rates test period, Mr. Roe, what are the dates for the low rate test period?

A The lower rate of production that was the second production phase of the test period was at the current pool allowable rate and that was a period that the production began on November 20th and ended on February 20th of 1988, November 20th being in 1987.

Q How many total days were covered in that low rate test period?

A That covered a 92-day test period, or approximately 3 months.

Q And what was the total gas produced during the test?

A During that 3-month period 948-million cubic feet of gas was produced.

Q And what is the total oil produced during the test?

A 143,400 barrels of oil.

Q And what was the total psi drop during the test on an average basis for the Gavilan Mancos reservoir?

A The -- 23 pounds for the total period.

Q And when you reduce that to a psi drop per pound in a month, what number do you get?

A The exact number, if you divide 23 by the 3.03, is 7.6. I probably will refer to it as about 8 pounds, though.

Q When we look at the results from the observed data in the high rate test period, Mr. Roe, did you find any of the Gavilan Mancos Pool wells that could pro duce at the top oil allowable?

A No. There were, during the high rate of production there were no wells that were limited by the allowable that was -- or the allowable that was established for that period.

Q For the oil?

A Right.

Q During the high rate test period did you find any of the Gavilan Mancos wells that could produce at the top gas allowable?

A I reviewed the data from, the actual production data from that period and there were no wells that produced at top gas allowable, either.

Q When we talk about producing at various gas/oil ratio limitations throughout the life of this reservoir, if we establish that gas/oil ratio at 2000-to-1, and make that effective after this hearing, are you satisfied that that can remain a permanent solution for this reservoir?

A No, and as a matter of fact, from this point forward the volumes of gas to be produced from any individual well will be increasing on a monthly basis.

Q In reviewing the information from the testing period have you had an opportunity to review Mr. Weiss' preliminary report that he submitted to us and the

Commission in May of this year?

A Yes, I have.

Q And have you had an opportunity to review his final report submitted in the hearing earlier on Monday of this week?

A Yes.

Q And were you present to hear Mr. Weiss' testimony before the Commission on Monday?

A Yes, I was.

Q Let me direct your attention, Mr Roe, to that portion of Mr. Weiss' report which is found on page 8 of his report.

If I might approach the witness, Mr. Chairman?

MR. LEMAY: Fine.

Q Mr. Weiss has analyzed the wells and he has tabulated some 87 wells, I believe it is, within his study.

A Yes, he has.

Q And in your review how many wells in the Gavilan Mancos Pool were included in the study?

A There are only 74 wells that are completed and available for production in the Gavilan Mancos Pool, so I'm sure that he did include some wells from the West Puerto Chiquito Pool.

Q If we look on the 74 wells in the Gavilan Mancos Pool, Mr. Roe, would you refresh our recollection and describe as concisely as you can the method by which Mr. Weiss analyzed the results to get to his 46 wells that he's shown us in that paragraph on page 8?

A Okay. Well, Mr. Weiss was presented with the same information that each of the operating operators within the pool were presented with, which was a tremendous amount of production in terms of barrels per month or actually barrels of oil per day, and the gas production such that he could compute the gas/oil ratio and the daily average, or use the daily average that was provided.

There were -- Mr. Weiss used both, both sets of data.

Q Do you agree with the method of analysis that Mr. Weiss has used when he's identified 46 wells as having the appearance of benefiting at the higher allowable rates during the high test period?

A Well, I -- I agree that what Mr. Weiss did is generally a good method to analyze the rate sensitivity if you are in fact plotting data that varies at random. The fact that the data generally plotted is reflecting pretty much the maximum capability of the wells throughout the total test.

Q Did all 46 wells that Mr. Weiss tabulated reflect the ability to be influenced by capacity rather than rate -- rather than the allowable?

A For the most part most of the wells were not limited by allowable. They were producing at capacity.

Q How have you identified and tabulated those wells that have the capacity using the higher rate allowable to actually produce more oil at a smaller gas/oil ratio?

A I've -- in one of my exhibits I have presented that information.

Q How many wells have you identified in the study that fit that classification?

A Of the 74 wells that are completed for production, there's 31 of them that are limited by the current pool allowable of 400 barrels of oil per day and 240 MCF per day for a 320-acre spacing unit.

My exhibit when we get to it will reflect that there are no wells that are limited by the allowable that existed during the initial production phase of the test period.

Q Have you identified and tabulated in your exhibit any wells that actually decrease in oil rate during the high test period?

A Yes, I have.

Q And how many do you tabulate?

A There -- during the test period there were -- my memory is not serving me as well as it should this morning. During the test period there were 22 wells that actually reflected an increase in production, an increase in the flow of production during the test period.

Q In your study, Mr. Roe, have you identified and tabulated any wells that after the high test rate period could not return to the level of productivity that they had immediately before that high test rate period?

A Yes, I have.

Q And how many wells do you get?

A From my review of the production records of all 74 wells there were 43 wells that did not return to the trend that was established prior to the initial phase of the production test.

Q We've had some questions earlier this week with regards to the 72-hour pressure build-up. Do you have an opinion concerning whether the 72-hour pressure build-up, do you have an opinion concerning whether the 72-hour build-up before the test was adequate?

A Yes, I have.

Q And what is that opinion?

A I believe that the 72-hour, it was not a randomly picked test. Mr. Chavez called all of the operators together. We agreed upon the test procedure based upon the pressure data we had to start with, and we mutually agreed that the 72 hours would be adequate and it was especially important to -- that all operators use the same procedures so that in the event there was some degree of unstabilization, although we didn't feel that would be a significant problem, but we would at least be comparing a 72-hour pressure in each well at different planes of pressure depletion in the reservoir.

Q Is that more important to you as an engineer in setting up a test than having wholly stabilized wells before the production test period?

A Well, it is to me, from the standpoint that quite a few of the wells in the Gavilan are equipped with artificial lift equipment such that obtaining a pressure build-up is possible only by either using fluid levels or removing the production equipment from the well. Once you've removed the production equipment from the well, then you've got to use some other method to get the well to produce at a somewhat stabilized rate before you start your build-up and requiring a fairly large expenditure on the part of any one operator, and so the Commission did not think that it was a justifiable expense to require each operator that was equipped with artificial lift equipment to gather production data from a pressure build-up and from the standpoint that we felt each operator would be obtaining a 72-hour pressure, if the engineers that agreed upon that test procedure felt that we would be adequate with 72 hours.

Q Apart from -- regardless of the expense apart from the voluntary agreement of all the operators for the test period, are you confident as a petroleum engineer that 72 hours for this test period is proper?

A Yes. Prior to the test period we had some pressure build-up data to indicate that many wells would build-up within the 72 hours. Some of the lesser productivity wells would require longer than that; however, as long as we were using a 72-hour build-up period for that well throughout the test period, we were hoping that we'd be comparing pretty much apples to apples at each of the three pressure test points.

Q In analyzing the results of the low rate test period, what did you find from the reports in terms of the production of oil per pounds of pressure loss during the test?

A During the second phase of the production test, which was the lower rate, we actually averaged approximately 6200 barrels of oil per pound of pressure loss within the Gavilan Mancos Pool.

Q When you analyze the results from the high rate test period in terms of barrels of oil produced per pound of pressure loss during that test period, what did you find?

A It averaged about a third of what we did during the second phase. The actual number was 2200 barrels of oil per psi loss.

Q Do you attach as an engineer any significance to that?

A Yes, sir, I do.

Q And what is that?

A Well, the -- basically it indicates to me that there was a significant amount of reservoir pressure dissipated during the higher rate of production that wasn't available for recovering oil from the reservoir than there was during the lower rate of production.

So our actual recovery efficiency from the reservoir in terms of barrels of oil recovered at the surface per pound of pressure loss was greater during the second phase of the production period by a factor of three.

Q And what conclusion does that allow you to draw as an engineer with regards to whether or not we should adopt the high rate test allowables for the pool or the low rate test allowables for the pool?

A Well, the basic conclusion is that with the amount of gas that would occur at the higher -- gas production that would occur at the higher rate, we make a better use of the reservoir energy that remains by producing at the lower rate.

Q Do you have an opinion, Mr. Roe, concerning whether the Commission, if they put the high rate allowables in place in Gavilan now as the allowables for that pool, will it protect correlative rights among the owners within that pool?

A No. In fact, later in my exhibits I'll have information to show you that correlative rights will be grossly violated.

Q Among operators and wells within Gavilan Mancos itself?

A That is correct.

Q Do you have an opinion as to whether if the Commission puts the high test rate allowables as the producing allowables as the producing allowables for Gavilan Mancos Pool there is the violation of correlative rights with regards to operations in any other pools adjacent to or in the vicinity of Gavilan Mancos?

A Yes, there will be.

Q What is the basis for that opinion?

A Well, Dugan Production has interest both within the Gavilan Mancos Pool, the West Puerto Chiquito Mancos Pool, and the Bear Canyon Unit to the north.

Q When you say the Bear Canyon Unit to the north, you're looking at the Amoco Bear Canyon Unit that is up in these four sections on this display?

A Yeah. We didn't get that outlined but basically it -- it covers the -- pretty much the northeast quadrant of 26 North, 2 West. It covers all of Sections 1, 2, 3 --

Q 1, 2, 3 and then we have 10, 11 and 12?

A Right, and then it covers the north half of the next row of sections below it, 13, 14 and 15.

Q The north half of these.

A Right. I'm sorry, I cut it off a little short. It covers all of 13, 14 and 15, and the north half of the row of sections right below it.

Q What is your concern with regards to the Bear Canyon Unit and the operations in Gavilan Mancos Pool if the Gavilan Mancos Pool goes to the higher rate allowables?

A Because there is not a secondary recovery process within the Gavilan Mancos Pool and there is an effort to maintain pressure within the West Puerto Chiquito Mancos Pool, we would expect a pressure differential --

Q I'm sorry, Mr. Roe, I didn't make myself clear there. I'm talking about the Bear Canyon to the north and it's relationship to Gavilan.

A Okay, I'm sorry, I didn't understand.

Q Do you find that those two -- two pools are in communication?

A It is my opinion that they are. There's not a whole lot of information available. The Bear Canyon Unit is just being developed, but the information that is available does suggest communication with the Mancos in Bear Canyon with the Mancos in -- within the Gavilan Mancos Pool.

Q Let's address now the question of the inflow from West Puerto Chiquito Mancos into Gavilan Mancos. Do you have an opinion as to whether that's occurring?

A I feel that right at the current time the unit operator is making a real effort to maintain a similar pressure on the east side of his unit as exists within the Gavilan Mancos Pool; however, with continued pressure depletion in the Gavilan Mancos that is going to become more and more difficult to maintain a balance and still maintain their pressure maintenance effort within the Canada Ojitos Unit.

Q Let's talk about Gavilan Mancos Pool itself, now, Mr. Roe. Have you made a calculation and do you have an opinion at the higher rate allowable what the remaining primary life is for Gavilan Mancos?

A Well, at the -- during the initial

phase of the production test period we were depleting pressure at the rate of 45 pounds a month and the reservoir pressure is currently at a level that we have approximately about 16 months worth of life left if we continue the 45 pounds per month pressure depletion rate.

Q And if the Commission continues to use the lower rates as the allowables for the Gavilan Mancos Pool, what is your opinion with regards to the remaining primary life of Gavilan Mancos?

A Well, again, at the average pressure decline of 8 pounds a month, which probably is not totally realistic to project that 7 or 8 years into the future, but that's basically what you get by taking the remaining pressure and following the 8-pound per month pressure decline established during the second phase of the production (unclear.)

Q Let's turn now, Mr. Roe, to your Exhibit Number Three.

Mr. Roe, your Exhibit Number Three is a tabulation, the first of which is on legal size paper. The next one is stapled on a letter size piece of paper that's got a plat on it of the Gavilan Mancos Pool? Do you have that, sir?

A Yes, I do, and while we're looking at that plat, I would -- the top line of the Bear Canyon Unit is indicated.

Q All right, just a moment, let's make sure we all have this exhibit. No, that's not it.

First of all, Mr. Roe, would you identify the first page of the exhibit and simply describe for us how to read and understand the display?

A The first page of the exhibit identifies or sets out the wells that -- within Gavilan, plus several of the wells that were within the West Puerto Chiquito Mancos Pool that participated in the Commission Order testing of both pools during the period beginning June 30th of 1987 and ending on February 23rd of 1988.

Q You're summarizing the bottom hole pressure test results?

A Yes. I've actually taken the data that was accumulated and adjusted it to a common pressure datum for each well and that datum is a +370 feet above sea level, which is a datum that pretty much was agreed to during the operations of the Engineering Study Committee, and it's a pressure datum that pretty much continues to be used.

Q Let's start, first of all on the left. We have a column that shows the operator. You decide where we go in that tabulation and let's pick a sample well and follow it across the display and see how to understand the tabulation.

A Okay, if we could just use the second well down, that would be a well that's operated by Sun Exploration and Production.

Q This is the Loddy Well?

A Yes, that would be the Loddy No. 1.

Q And your other exhibits focus in on some of the information about the Loddy Well?

A Yes.

Q Well, let's use that one, then.

A Okay. During the initial measurement of bottom hole pressure which occurred on June 30th of 1987. the bottom hole pressure, as I've adjusted it to a pressure datum of +370, is measured to be 1066 psia.

During the second measurement of bottom hole pressure test which occurred on November 19th of 1987 --

Q This is the low rate test period.

A Well, actually the production that occurred between June 30th and November 19th would have been the higher rate of production.

Q So the first -- the next three columns, then, is going to be the high rate.

A Yes.

Q And the final three will be the low

rate.

A Yes, sir.

Q All right.

A In other words, that would be at the end of the low rate period.

So after we had produced at the higher rate of production for a 4-1/2 month period, on November 19th, 1987, we measured the pressure again and although it's not real clear on this tabulation, we shut both pools in on November 16th and -- at 8:00 in the morning, and then after 72 hours we measured the pressure on November 19th, and the pressures you see under the BHP at +370 psia is the pressures that I have arrived at by taking the pressures at whatever datum they were measured and converting to the +370, and for the Loddy No. 1 that was 876 psia on November 19th.

Q When we move to the next column we see a -190?

A Yes, which -- which reflects that during the production period that began on July 1st and ended November 16, we reduced the pressure from 1066 to 876 for a total of 190 psia.

Q And that gave you a delta P pressure per month of the -41.9?

A That is correct.

Q Okay. Contrast that for us now when we go to the low bottom hole pressure, the results of the bottom hole pressure test taken from the low rate period.

A Okay. During the low -- the second phase of the production period, which began November 20th, 1987, and ended on February 20th of 1988, the wells were shut in on February 20th and the pressure measured on February 23rd. Again taking the pressure that was accumulated and converted into a datum of +370 and converted that to psia, the pressure in the Loddy had now declined to 786 psia.

Q The next column shows a -90?

A Yes, that is the --

Q What is that?

A That would reflect between November 19th and February 23rd the second phase of the production test resulted in a loss of pressure of 90 pounds during the 3-month period for an average of approximately 29.7 pounds per month.

Q The summary of bottom hole pressure test results includes part of West Puerto Chiquito Mancos?

A I have included some wells from the West Puerto Chiquito Mancos Pool basically to reflect their relationship to the wells within the Gavilan Mancos Pool, yes.

Q Let's go down and look at the BMG well, it's the A-20 Well?

A Yes, that would be the second well from the bottom.

Q The Section 20 well here, the A-20, is in the expansion area immediately adjacent to the main project area?

A That is correct. It's actually located within the -- it is within the Canada Ojitos Unit but it is not within the pressure maintenance area as authorized by the Commission.

Q All right, let's look at that one and get over to the bottom hole pressure test in the high test period, the -48.2?

A Yes.

Q And what is that number then?

A Well, that -- that reflects that during the production period, the initial phase of the production test, which with that well did -- the wells in the West Puerto Chiquito Pool also participated in this test -- it encountered a pressure loss of 48.2 psi per month on the average throughout the 4-1/2 month production.

Q And the B-32 Well right below that is also a well in the expansion area. It's located here in Section 32?

A Yes, it is.

Q When we look at the results of the pressure test for the low period, which is the last column on the far right, what do you see for both of those wells?

A Following the second phase of the production test the E-20, or the Unit Well No. 36, had an average of about 6 pounds per month pressure loss and the B-32 experienced an 8 pound pressure -- 8 pounds below pressure loss.

Q What are your principal conclusions from this analysis as depicted on this display, Mr. Roe?

A Well, during the second phase of the production test I feel the data clearly indicates that we recovered more oil per pound of pressure reduction in the reservoir. The average of the 17 wells that I present on this tabulation is 6200 barrels of oil per pound and it ranged from 1600 to 8950 barrels of oil per pound.

That, compared to the initial phase, which would be the high rate of production, the recoveries from the reservoir were about a third; the average of all 17 wells was 2200 barrels of oil per pound and the range, the individual well range, was 1050 to 3550.

Q Would you turn to page 2 of Exhibit Number Three and show us what that is?

A Page 2 is nothing more than just a base map reduced to a scale that fits on 8-1/2 x 11 paper, and with the orange coloring I've identified the wells that were -- from which pressure measurements were taken during the test phase.

MR. KELLAHIN: Mr. Chairman, we move introduction of Dugan Production Corporation Exhibit Number Three.

MR. LEMAY: Number what?

MR. KELLAHIN: Three, sir.

MR. LEMAY: Three? Exhibit Number Three into the record without objection.

(Thereupon a brief discussion off the record.)

Q Mr. Roe, let me direct your attention to Dugan Production Corporation Exhibit Number Four. It's included in your legal size manila folder in a reduced copy --

A I tell you, Mr. Kellahin, this has got to be -- prove that when we see something we think is a good idea, we really go after it.

Q Mr. Roe, is the information depicted on Exhibit Number Four your work product, sir?

A Yes, it is.

Q And what is the source of the information you used for this display?

A The pressures, first off, this display is a plot of bottom hole pressure again at the datum of +370 for many of the wells that we have pressure from throughout the Gavilan Mancos and some in the West Puerto Chiquito Mancos Pool.

It's a plot of that pressure versus cumulative oil production from the Gavilan Mancos Pool and we've transposed the plot for the gas/oil ratio throughout the productive life of the Gavilan Mancos, and so that you can identify points in time, above the gas/oil ratio curve we occasionally state what month that is, each of the months that's plotted, so between January 4th and January 5th of '85 each of the dots is an individual month throughout that timeframe.

Q Let's take a moment and find some of the information on the display.

First of all, when we look at the vertical axis, what have you plotted on this axis of the display?

A The vertical axis reflects the pressure scale and again we're dealing with pressure at the datum that we've selected.

Q For the Gavilan Mancos Pool, then, if we look up on the pressure scale we find up here 1700 pounds?

A Yes, that is correct.

Q When we read the bottom scale what are we looking at the bottom scale?

A Okay, on the bottom we've presented the cumulative oil production from the pool in thousands of barrels.

Q For this portion of the center scale here that goes vertically, you have simply taken the left margin scale and put it over here so you could make a closer comparison to the slope you find for the pressures over here?

A That is correct. We basically just moved the scale a little closer to where the pressure data was.

Q When we track the gas/oil ratio for the Gavilan Mancos Pool and you've identified GOR on different points, are we following this plot from left to right as we go up the display?

A Yes, that is correct.

Q And that is for the Gavilan Mancos Pool wells exclusive of the expansion area?

A That is correct.

Q Now for the pressure information, for example, on the Dr. Daddy-O Well that's shown up here, there is a circle?

A Yes.

Q What does that indicate? What does the top circle show?

A Okay. Basically that reflects the individual pressure point that we had in the Dr. Daddy-O at that point in time and roughly that's a pressure of about 1720 and it occurs at a cumulative production of approximately 800,000 barrels of oil from the pool.

Q When we go to the next circle for the Daddy-O well that's tied in by this straight line, when we get to this point what is that?

A The pressures that were picked, that would be the second pressure measurement that we have on the Dr. Daddy-O, so in all cases when we had one well that we had subsequent pressures on we have tried to track that pressure history by connecting the points with the line so that you can follow the pressure decline in any one well.

Q For example, if we chose the Loddy Well, shown in here in highlighted coloring --

A Yes, and on the individual plots that were handed out I think we've identified the Loddy pressures in orange.

Q Okay. When we look at this first dashed line from here to here on the display that you have arrowed and put a caption 11,000 barrels of oil per pounds of pressure?

A Okay.

Q What have you done here? What is -- what is this slope?

A Basically we were just drawing a visual average through the pressure data we had during the production from the pool that occurred up through about 2-million barrels of oil. So during the initial 2-million barrels of oil production the rate of recovery from the reservoir averaged about 11,000 barrels of oil per psi loss in reservoir pressure.

Q When we get to that portion of the display that shows a change in slope from the former slope, you've identified that with another dashed line?

A Yes, I have.

Q And that one is captioned 3400 barrels of oil per pounds of pressure loss?

A Yes.

Q Okay. What have you shown here then?

A Well, basically, beginning at roughly 2-million barrels of cumulative production from the reservoir, which is from a point in time, that was approximately in March or April of 1986 and you can get that time frame from -- from the gas/oil ratio curve.

Q You put the dates on the gas/oil ratio curve?

A Yes. That is -- well, we put the dates periodically and you can get from one date that we put to the next date by each little circle is a month.

Q All right, this -- this date for January '86 that's arrowed to the gas/oil ratio will also fit if you take it on up and project it into the pressure decline slope.

A Yes. Yes, that is correct.

Q All right.

A In other words, finding a point in time is a little bit awkward from this kind of a graph but -- but it can be done by putting the dates on the gas/oil ratio curve.

Q So you can make a comparison between the gas/oil ratio curve and the slope of the pressure that you have done up here on this part of the display.

A Yes, sir.

Q All right, let's go back, then, to January of '84 and have you describe what's occurring in the Gavilan Mancos Pool up to this point in time in the reservoir.

A Okay. Prior to January 1st of '84 there was not a whole lot of production from the pool. We didn't go back from the date of first production because it was small and it added a great amount of paper to our graph.

The, basically the first significant points of interest began in 1984 and at that point we had approximately 10 wells in January of 1984 that were ready for producing and basically on production from the Gavilan Mancos Pool.

Q As we compare the gas/oil ratio to the pressure plot, this slope here, between January of '84 and January of '85, what conclusions do you draw?

A Well, the rate of pressure decline from the Gavilan Mancos Pool was fairly limited. In fact, it was averaging about 5 psi per month.

Q When we compare the information from January, '85, to January of '86, we see a rate of pressure decline on a monthly basis of what, sir?

A It actually is declining at 5 pounds a month and if I said 11 psi per month just a minute ago, between -- during 1984, which I think I did, that really should have been 5 pounds per month.

Q It's when we get to January of '86 and beyond that you now find the slope change.

A In fact the -- the rate of pressure depletion from the reservoir occurred right around March or April of 1986.

Q Show me on -- on the display approximately where the Commission took action in September 1st of

'86 to reduce the allowables in the Gavilan Mancos Pool.

A Okay, that basically is the --

Q All right, let's start with the Loddy pressure. Could we take the Loddy pressure and slide down that pressure?

A Okay.

Q Where are we going to show action by the Commission?

A Well, the particular way the data is presented on -- on this graph, it isn't quite as obvious on the Loddy. I would refer to an earlier graph that presented a rate of pressure versus time. It's a little easier to see how pressure varies with time from that, and I would particularly refer to Dugan Exhibit Number Five in Case 9113, which I like to say was a plot of pressure versus time and later in our exhibits we'll have this plot again and I'll be able to -- to refer to that, but pretty much prior to September of 1986 pressure in the Loddy, and the reason that we would like to use the Loddy as an example is this is a well that was shut in in the reservoir and not producing for the reason that we just could not obtain a pipeline connection. Dugan Production was operating this well for Mr. McHugh at the time and so we chose to utilize this well as a pressure observation well.

Prior to September of 1986 the rate of

pressure decline in the Loddy was averaging 47 pounds per month.

Upon the allowable reduction that occurred in September of '86 that rate of pressure decline changed to approximately 33 pounds per month and it gradually worked its way on up again to 39 pounds a month, indicating that the reservoir voidage was only temporarily restricted by limiting the gas/oil ratio.

Q Prior to the Commission action in September 1st of '86 were you seeing a slope change occurring in the reservoir at higher rates?

A Yeah, we actually experienced a change in the rate of pressure depletion prior to the Commission ordering a reduction in allowable, which is one of the things that I think guided the Commission in ordering a reduction in allowable.

The actual point on this graph if we go to a point along the gas/oil ratio curve to where it flattens there.

Q Right here?

A No, go on up to the next one. Yeah.

Q That would be September of '86 and that is the point that the allowables were reduced and, as you can see, by that point in time the pressure in the reservoir had gone from an average decline of 5 pounds a month prior to, say, October of '85, it had begun declining at an average of 30 pounds a month. And that pretty much is what we think resulted in the shift in the pressure recovery -- or the oil recovery curve from 11,000 barrels of oil per pound, which is reflected on the pink curve, to --

Q All right, let me focus in on that for a moment.

We have a slope of the pressure loss up here going as depicted on the pink curve. We have the Commission changing to a lower allowable rate and the slope becomes just over a third of what it was before.

Was that a result of the Commission reducing the allowable days?

A No, not -- no. The actual -- that slope change had occurred prior to the Commission issuing the order reducing allowables and pretty much that, the fact that we had had a slope change and the pressure had begun declining at 30 pounds a month was one of the things that at least concerned me as an operator within the Gavilan and there were other operators that were concerned that irreparable damage would be done to the reservoir.

Q When the Commission took its action to reduce the allowable rate, why don't we see this slope for the green dashed line decrease?

A Well, I wish that we could show the Commission that but there were several things happening in the reservoir and that's why I wanted to talk about the other pressure graph that we'll have later in our exhibits.

We did see a slowing in the rate of pressure decline, which you can't tell from this plot here because about the time that the Commission issued the allowable reduction we also had a pretty dramatic increase in reservoir voidage, not only because the wells were increasing in gas/oil ratio and free gas production, but also the number of wells that were beginning to be placed on production was really increasing.

For instance, when the Commission first became concerned and called all operators to Santa Fe in March of 1986 to address this issue, there were just 30 wells producing from the Gavilan Mancos Pool, and at that point in time the reservoir pressure was only declining at an average of 5 pounds per month.

By September, the first month that the allowable reduction was effective, there was a total of 41 wells producing and the rate of pressure decline had accelerated to 30 pounds a month, and you see the effect on the reservoir recovery by us shifting from 11,000 barrels per pound to the 3400 barrels per pound.

Now about this same period of time one other event that was aggravating matters in Gavilan was the wells that the Canada Ojitos Unit operator were drilling to address the, you know, the drainage issue from the -- or his protective wells that are pretty much located within what we call the pressure maintenance expansion area. It would be the two western rows of sections in the Canada Ojitos Unit. During this period of time those wells were being drilled and being placed on production, and that resulted in a tremendous change in the reservoir withdrawal and to some degree you can see that by the distance between the two points, the cumulative oil that occurs between any one month, those distances becoming shorter and shorter, or longer and longer, I'm sorry, it refers (sic) that we were actually producing more and more from the reservoir.

Q What is your opinion as an engineer as to what would have happened to the green slope in the absence of the Commission reducing the allowable?

A Well, had the -- had the Commission not reduced the allowable, I -- I haven't really followed that thought all the way out, but my guess is that the reservoir pressure would have been depleted by now. I didn't follow --

Q Are you competent to tell us that in the absence of Commission action where would this slope be? Would it be above the dashed green line or below the dashed green line?

A It would have actually shifted quite a bit to the left of the green line, which -- which is actually to some degree reflected by the curve that we've highlighted in yellow.

Q Well, let's go to that curve. When we look at the yellow curve, what are we looking at here?

A Okay, that -- that pretty much reflects what happened during the -- the time that the production, or the initial phase of the production test that the Commission ordered.

Q This is the high rate test period.

A Right, and that pretty much, in my way of thinking, I did not -- I do not feel that during the high rate of production period there were any wells that were producing with the restricted allowable, so pretty much what we could expect from the reservoir, with the fact that there is now in the range of 74 wells that could produce, there's actually only about 61 that are producing during this period, but this curve that we've highlighted in yellow would reflect what the reservoir -- how the reservoir will perform at the higher rate of production.

Q When we picked the Loddy Well, we've tracked the Loddy Well, or you have, along this line that's connecting the red dots?

A Yes.

Q And when we get to the Loddy Well again on the dashed yellow line, it is here on the display?

A Yes, it is.

Q And at the end of the test period, then, what happens to the Loddy pressure?

A Well, basically they -- during the test period we saw the wells within the Gavilan Mancos Pool actually perform in two different manners.

The Loddy, actually performed as did a group of wells within the Gavilan Mancos Pool. They reflected a higher rate of pressure depletion during the test than did a second group of wells within the Gavilan Mancos Pool which we have highlighted in the -- with the blue line on this large graph.

Q Let's distinguish between the two groups now. What happens over here with the blue line?

A Well, we -- it is my opinion that the wells that we've highlighted with the blue trend, they pretty much reflected a lesser rate of pressure depletion during the test and the fact that they are all located towards an exterior boundary of the Gavilan Mancos Pool, that we feel there may be some pressure inflow from outside that boundary; in other words in all cases, I'm not talking just the -- towards the West Puerto Chiquito Pool, but also north towards the Bear Canyon Unit.

Q All right, when you contrast the two lines, the dashed yellow line with the dashed blue line, you have wells in this group and wells in this group, the relationship in Gavilan Mancos and West Puerto Chiquito Mancos tells you what, if anything, with regards to observations concerning a boundary between the expansion area and the main injection project area of Canada Ojitos Unit?

A Well, it indicates to me that the wells that are in the upper trend that we've highlighted with the blue line, are receiving some sort of a pressure support that is -- that the wells in the lower line that we've identified with yellow are not receiving, and I believe that that is an indicator that the wells along the eastern edge of Gavilan, we've got a few wells in the Canada Ojitos Unit in there for informational purposes only, but they basically are reflecting a higher pressure, I believe, because they are receiving pressure support from the unit.

Q Let's look specifically at the orange line. Do you see the blue dashed line; when we get to the bottom of it it's got a little hook on the end?

A Yes.

Q If we look at the end of the yellow dashed line and then you have a dashed orange line, down here another little hook?

A Yes.

Q Is there any difference in the slope of those two hooks on the end of each of those displays?

A Yes, there's a pretty significant difference between the two, the wells in the upper set of wells, between the two points that we measured pressure in the (unclear) at the low rate of production, the recovery efficiency from the reservoir was 8900 barrels of oil per pound, which contrasts to the average of 2100 barrels per pound that these wells exhibited during the high rate of production.

Q Mr. Douglass raised yesterday with Dr. Lee the information from your testimony in the March, '87, transcript. It's found on page 214 of that transcript, Mr. Roe. Do you have a copy of that?

A Yes. Yes, I do.

Q I have taken a copy of the Proponents Exhibit Number Twenty and put it in front of your Exhibit Number Four for a moment so you can aid me in an explanation of the basis upon which you were making the testimony in March of 1987 concerning what you found to be a pressure loss in terms of pounds per year in the Canada Ojitos Unit. Would you tell us the basis upon which you made that statement?

A Well, I -- I used data that pretty much was provided to me through my review of -- during this period of time I worked, I don't think it's any secret, I've worked very closely with Mr. Greer and had access to a tremendous amount of information and I -- during this time frame we were concerned with Gavilan declining at 5 pounds a month where prior to that the unit had declined at a considerably lower rate. So --

Q Give us a point of reference. You've used 20 years in the testimony. What's the -- what's the time period?

A Okay. Basically I had access to some information that Mr. Greer had from some of his injection wells. In particular he had shut one of his wells in and used it as a pressure observation well and the 11 pound per year figure that I quoted during my testimony came from -- the particular time frame that this covered was, say, 1972 through mid-1980. That particular well did decline in its pressure, and again, we -- we were not measuring bottom hole pressure, so there is a variable there; however, because this well was in the gas cap area and Mr. Greer during this time made some effort to be sure that there was nothing but gas in the tubing, and he did this by periodically displacing the tubing and casing with gas, such that we know there was nothing but gas in the tubing, we feel that the injection or the static pressure that we observed in that well during this time frame, the '72 through early

'80, does reflect what was happening within the West Puerto Chiquito -- or the Canada Ojitos Unit, the pressure maintenance project, and that was an average of about 11 pounds per year during that time frame, and we had, at the time I quoted the 20 years, I think that was 1987, and I probably stretched 17 years just a little but we still had no reason to think the pressure wasn't performing along those trends because of our continued observation of the pressure in the gas cap area.

Q Taking that information, now, and integrating it with the information you have observed and analyzed concerning the pressure test period, do you see a pressure barrier between the pressure maintenance project itself and the expansion area and Gavilan on the other side?

A No, I don't. In fact I think that my explanation for the fact that during the high production rate we start seeing where prior to the June 30th pressure measurement all of the pressure data points fell within a fairly reasonable range. In other words, you could take a bracket and draw down through there, and we have pressure data for many other wells that that are not on this plot. I just -- but most of the other wells only serve to confuse the plot, but we have lots of pressure data that prior to 19 -- June 30th of 1987, all wells within the Gavilan

Mancos Pool pretty much followed the common trend and within a fairly narrow range.

Beginning with the high rate of production in the initial test phase, we start seeing those wells deviate and the separation, or the range becoming wider and wider, and in fact it's wide enough that I have actually broken it up into two trends, one that I've identified with the blue line and one with the yellow, and the inference to me is that the wells along the blue trend are receiving a pressure support.

Q At a lower rate of withdrawals, then, the pressure support from the project area is able to stop to some extent the withdrawal rate from the expansion area into Gavilan?

A Well, yes, we see that from the fact that the yellow curve, is is more removed from the pressure maintenance area to the wells along that trend and they experienced a higher rate of decline than did the wells along the blue trend, which are closer to the unit, and also the fact that the wells that are more removed from the Canada Ojitos Unit, they did reflect a flattening in trend, this was identified by the orange line, as we move into the lower rate of production.

Q Let's look at the gas/oil ratio plot, now, Mr. Roe. Let me follow along with the pointer on the gas/oil ratio plot and you tell me when I get to the point where the Commission took action in September 1st of '86 to restrict the gas withdrawals from Gavilan?

A Okay, that's September, '86, right there.

Q Can we conclude from this analysis, Mr, Roe, that when the Commission took action to reduce the rate, that the gas/oil ratio shoots up?

A The gas/oil ratio did increase.

Q Is that result of the Commission taking action to reduce the rate?

A I don't believe so. In September we had 41 wells producing. In October there were 48 wells that were producing. So between that one month period there were 7 wells. Like I said earlier, this is a time period that within Gavilan we had potential for 100 locations with the wells drilling or well locations and the wells being completed, and so the rate of withdrawal is increasing dramatically. Like I say, from September to October there were 7 wells added plus 2 wells in the boundary area of the Canada Ojitos Unit were placed on production.

Q Your analysis shows you that this increase in gas/oil ratio is attributable to simply the increased withdrawals from additional wells in Gavilan?

A Well, that's one of the reasons it went ahead and inclined.

Q What are some of the other reasons?

A Well, not all operators were -- actually reduced their rates of production during that early or late period of the restricted allowables.

Q We have certain wells that in Gavilan Mancos that were producing more gas than the gas/oil limitation established in September 1st of '86, and that would explain for some of the rise in the gas/oil ratio during that lower rate period?

A Yes. The -- basically we did see a drop in oil but basically some of the higher, bigger volume wells did not restrict their rates correspondingly, so a reduction in oil from the pool but continuing on at higher gas/oil ratios is reflected and is a little misleading from the standpoint it does look like there was an increase in gas/oil ratio resulting from the reduced allowables.

Q As we move up, then, the gas/oil ratio, at what point do we then have a significant event in the gas/oil ratio upon which you would like to comment? What happens in December of '86? We have a drop in the gas/oil ratio and it bumps back up?

A Well, the -- in December of 1986, I didn't look at that particular month, but my guess is we had 49 wells in December and in January there were 53 wells producing, and so I feel probably what you're seeing here, because this reflects total from the pool, where there was some additional wells placed on production, 4 additional wells, that some of those wells coming on at lower gas/oil ratios would actually reflect a poolwide reduction in the gas/oil ratio, which is a little confusing.

Q As we continue up the gas/oil ratio curve we get to a point here between December of '86 and July of '87 that drops, and then it goes significantly higher. What is occurring here in the reservoir, Mr. Roe?

A Okay, the reservoir, again bearing in mind that I -- I picture what happens in a reservoir as the -- I interpret the reservoir as having a very good internal communication throughout the reservoir, and so what happens at any one point in the reservoir is affected by what's going on at other points in the reservoir.

Now, particularly two months that are reflected on that peak in the gas/oil ratio curve are --

Q The two months?

A Yeah, the peak would actually be June of 1987 and the earlier bump would be May of 1987, and what -- the distortion that makes that gas/oil ratio curve jump up there, and you see this on all of the gas/oil ratio curves we've seen presented so far, there were some wells that -- I'll use Dugan Production as an example, We had a pump stick and so during June of 1987 we had no oil production because we, for one reason or other, did not jump out there and replace the artificial lift equipment immediately, which, considering that the well averaged -- was averaging between 1 and 3 barrels per day preceding that, there wasn't any great economic incentive for us to -- to rush to do it. So during June we had no oil production but we left the casing open to produce, and so during June we had no oil and 1267 MCF of gas production. Again a small volume but it reflects added gas with no added oil.

Now we had a couple of other operators that also had a similar relationship of their gas and oil for one reason or another, and, for instance, Mallon Oil during June of 1987, he only produced 118 barrels of oil but he had nearly 12-million cubic feet of gas.

A couple of other operators had high gas/oil ratios, probably not accounting for a whole lot, but when you have that distortion in your gas/oil ratio curve, or your relationship of oil and gas production, it distorts the poolwide GOR curve.

Q What occurs with the balance of the gas/oil ratio curve when it makes this big U-shaped dip and then comes back up?

A Well, pretty much that time frame is --

is the July, August, September and October of the initial phase of the production testing and during that period --

Q Take me through and tell me when we're seeing the effects of the high rate test period.

A Well, basically you're first effect was there, that was --

Q Right here?

A Yes.

Q This is July?

A Right.

Q August?

A August.

Q September?

A Right.

Q October?

A Yes.

Q November?

A Right.

Q December?

A Yes.

Q All right.

A Now, again, the significance there, and again, I'm not sure why there was a distortion in June's gas allowable or gas production with respect to oil production, but if you contrast any particular operator's oil production, gas production, and gas/oil ratio, which you can do by looking in my Exhibit Number One, I present the operator totals and again those are the production statistics that are on file with the New Mexico Oil Conservation Commission, the C-115 reports, but if you contrast what was happening in any operator, April, May, June, you can see that the shift in oil and gas production was not, in my opinion, related to what was happening in the reservoir; probably it was something more mechanical.

So the actual gas/oil ratio reduction as we go from the period preceding July and compare July to it, if the contrast is not as great as it would appear by June's gas/oil ratio to July's gas/oil ratio, it's quite a bit misleading.

Q Are there any further points on the gas/oil ratio display that you'd like to comment on?

A Other than I would point out that the August gas/oil ratio is going down with respect to July, but the September and October gas/oil ratio are actually starting to exhibit an incline and to me it is an incline that I -- I can realistically project the gas/oil ratio projection from the trend that was established with the last month being March of 1987.

So I have not dug into it to the degree that I probably would like to, but I do feel the gas/oil ratios that are depicted with May and June, are a little misleading and to compare what happened to the pool gas/oil ratio during the high rate of production to the May and June to the May and June allowables, it was -- it could leave with you with the misguided idea of what was happening in the reservoir.

And again we see this on the individual production curves which we will go into in my last exhibit.

Q (Not clearly understood} per pounds of pressure loss and we get to the end of that curve and we have the orange hook on the end, what is the barrels of oil per day per loss of pound of pressure for this period?

A The -- during that period those wells, and again, there's nothing magic about that line, that is an eyeball average through there, but it's 8900 barrels of oil per pound loss of pressure that that small group of wells exhibited during the second phase of production of the Commission ordered test.

Q And what is the barrels of oil per pound of pressure loss for this portion of the display following the yellow dashed line?

A During the -- that was a 3700 barrels of oil per pound, and again I stress, I found that, I guess there's a real need to qualify all of your numbers. but that is an eyeball average, that's not a mathematical average of that data, but it does represent the trend established by that group of wells.

Q What is your principal conclusion with regards to that observation?

A I believe that the shift in the range between wells that we now see within Gavilan, and the relationship of the recovery efficiency in terms of barrels of oil per psi pressure loss, my explanation for that is that the wells that are located in the general proximity of an outer boundary of Gavilan, that you could receive a pressure support. I believe they are receiving pressure support. Wells that are located towards an outer boundary of Gavilan or within the gut of Gavilan that aren't a same proximity to a possible pressure support, it is more evident to me that they aren't receiving a pressure support, so pretty much the wells identified by the yellow trend are going to be how the heart of Gavilan performs under a high rate of production. The wells in the blue trend would depict pretty much the future performance under unrestricted rates of production of wells towards the outer boundaries of Gavilan.

MR. KELLAHIN: Mr. Chairman, at this time we would move the introduction of Dugan Production Corporation Exhibit Number Four.

MR. LEMAY: Exhibit Four into

the record without objection.

Q Were you present in the hearing room this week, Mr. Roe, when Mr. Elkins identified and described Proponents Exhibit Number 36?

A Yes, I was.

Q In fact you've been present throughout the week and heard all the testimony of the witnesses?

A Yes, I've been here.

Q Let me take you back to this exhibit. Would you explain it in English to me as an engineer, what are we looking at here in Mr. Elkins display when he shows us rate of pressure decline in pressures per minute?

A We're basically identifying a rate of pressure change. In this particular paper they were relating it to psi per minute but it would be similar to what we've been talking about so far in the rate of pressure change within the pool, and that's what they were, I'm sure trying to approximate, is draw a relationship by reservoir pressure change to something they could do in the laboratory.

Q And Fawcett (sic) and Muscat have got a display here to show engineers that if we can get a large enough pressure differential in operation conditions in a reservoir and get above where the plot says recovery not rate sensitive, we can get to a point in the reservoir where the pressure differential measured in pressure versus minutes, is going to be enough that we're going to improve recovery out of this matrix if it's there.

That's what I understood this graph presents. Now I do want to qualify. I have not read this paper. I am trying to operate with the understanding that was given to me yesterday seeing this exhibit.

Q Taking that basis of knowledge, can you tell us operationally in Gavilan Mancos if we can get to a pressure decline in psi per minute that will get us out of this range where recovery is not rate sensitive?

A The -- it's my opinion you can't. During the high rate of -- the unrestricted rate of production, therefore the higher initial production phase of the test period. We've already indicated that during that time, and I believe that there were no wells producing with a restricted rate during that phase, we -- we saw the rate of pressure change of 45 pounds a month.

Q What's that to us in terms of psi per minute?

A That would be, if my able helper's math is exactly right, it would be .001 psi per minute.

Q .001. On this display, in order to get rate sensitivity, what must we get to in psi per minute to show the benefits of that pressure differential?

A We need to get a rate of pressure depletion that would exceed 1 psi per minute.

Q You need one point.

A Yes, sir, 1000 times more than we were actually encountering during the rate of pressure depletion during the high rate of production test.

Now, now, I might comment, also, too, I again qualified my statement because I am not sure what all is behind this but it's my understanding that this particular sample had a matrix permeability of 480 millidarcies and a porosity of 22 percent. It would be my belief that when we deal with what kind of -- if -- if we accept that a matrix exists at Gavilan, which we do have core analyses that give us some numbers we can quote, the average porosity in Gavilan is not 22 percent, it's more in the range of 2 percent, and I stress, that's a porosity at ambient conditions. I have, my -- my belief is when you put the overburden condition, that porosity is no longer 2 percent, it's down to around -- less, less than 1.

Also, our --

Q Let's talk about the core. Let's talk about the Gavilan Mancos cores. We've got the Mallon Davis core?

A Well, that's one of the cores that we have as a data base, yes.

Q I'm interested in the information on the field observations of the core sample that was taken out of the wellbore and analyzed in the laboratory and witnessed by various members of the operating working interest Gavilan group. Now which core is that?

A Well, the only core from the --

Q That's going to be the Mallon Davis core.

A Yes, the Mallon --

Q That's the one --

A -- Davis core.

Q -- that's the one that involved Mr. Ellis.

A Well, Mr. Ellis wasn't actually involved with the core at the well site. In fact, the only company representative at the well site was Dugan Production's geologist, and Mallon Oil did have a consulting engineer on location.

Q Tell me how the core was handled, how it was taken to the lab, and what were the observations at the laboratory with regards to this core.

A Okay. At the well, and again bearing in mind this core was taken under the planning and direction and guidance of a group of operators that formed the Engineering and Geologic Study Committee, so basically, we all paid for and we all planned and we all decided what interval we would core, and because it was convenient to have our geologist on location, he was there when we laid down all nine cores and one of his specific assignments by me, and he works directly under my supervision, and it was to observe what the core looked like when it came out of the core barrel before the roughnecks worked it down and got all of the mud off of the rig floor.

And his observation was that he saw no bleeding oil, and he relayed that to me in a conversation from the rig over our radio system.

Q What was then done with the core?

A At the well site it was cleaned up a little bit, although not very good. It was placed in the plastic core bags and immediately put in the core boxes in the refrigeration truck and taken to Terra Tech, this laboratory facilities in Salt Lake City.

At that point it was observed during a meeting of operators; the Geologic and Engineering Committee members that could make it were there to observe the core.

Q And what were the reported observations?

A Well, at that point in time there was still very little oil, in fact none, that had bled from the matrix of the core. In fact that was one of the reasons that the Engineering and Geologic Study Committee initially decided that they wanted to, as part of the report we wanted to photograph this core under a fluorescent light, is because the only oil fluorescence that we saw when we exposed the core to a black light was a very fine boundary that existed between the very fine sand lenses. In other words -- I say fine, very thin, there were no thick sands. We're dealing with a core that is many, many, many layers of very fine grained, highly calcareous cemented sandstone, very low permeability in the matrix because of the calcareous ce-menting, and interbedded with very, very thin shales.

The only oil fluorescence that that group, now I was not a member of that group but Mr. Ellis was and he and I work very closely, and Dugan's geologist was also there, the only oil fluorescence that the group observed was a very fine, inter -- I'm not sure what to call it, but as the fine grained sand was adjacent to a shale there was a little oil fluorescence, but that was the intent of photographing the core under the UV light, was to show that's where the oil saturation was, as it existed. Again, none of it had bled to the surface to the point that it would in a conventional sandstone that did have an oil saturation in it, and so, you know, again we're not deal-ing with a conventional matrix that we identify with normal oil producing reservoirs.

Now, I personally have observed at least one other core from -- taken from the Gavilan Mancos -- from the Gavilan Pool, and I saw nothing different. It was basically the same type of a rock and -- that we saw.

MR. KELLAHIN: It's up to the Commission, do you want to take a break?

MR. LEMAY: Well, yeah, I think so. Do you have some more?

MR. KELLAHIN: We have some more.

MR. LEMAY: Let's take a break, fifteen minutes. Be back here at quarter to 11:00.

(Thereupon a recess was taken.)

MR. LEMAY: We shall resume with the testimony of Mr. Roe. Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

Q For just a quick moment, Mr. Roe, let me direct your attention back to Exhibit Number Four.

When we look at the gas/oil ratio plot and we look at the circles which you and I have described as various months of the year, how was the data plotted in terms of that point?

A The actual gas/oil ratio is -- is the gas/oil ratio that existed during that month. The cumulative production that it's plotted against would be an average cumulative for the month. In order to check that number you would have to look at the cumulative at the end of the month plus the cumulative at the start of the month and divide by 2, and that would give you an average cumulative that would approximate the cumulative at the middle of the month and the only reason that that would be real important is if your gas/oil ratio is inclining at a significant rate, which in some parts of these curves it is. It would shift where you plot it if you plotted it at the end of the month.

Q That's how you plotted it.

A Yes.

Q When we look at the Mallon Davis core, the Mallon Davis Federal Well is located here in Gavilan, Section 3?

A Yes, it is.

Q Let's finish up with our discussion about the core.

Were core sections taken, analyzed, and observed from the A, the B, and the C zones?

A We -- we attempted to core all of the A, B and C. We missed our core point just a little and only got the lower part of the A, but all of the B and most of the C.

Q What was done with the Mallon Davis Well in order to attempt to complete, stimulate and produce the well?

A Well, the -- Mallon's engineer actually took care of all of that. The only involvement for the Engineering Study Committee was -- was the core; however, it's my understanding that it was -- well, from the records it was perforated in a similar manner as all other Gavilan Mancos wells were, and again, from the Commission records, it was stimulated in a manner that is very similar to the standard stimulation with a hydraulic fracture, frac (unclear) that is typical in the Gavilan Mancos Pool.

Q What is the current status as best you know it of the Mallon Davis Well?

A It, I'm sure, has been very discouraging from the standpoint of what has resulted. I -- it has never been a very good well and it's at best a marginal well and in my opinion probably will never -- never recover the investment required for the drilling and completion.

Q Let me direct your attention, Mr. Roe, to Dugan Production Corporation Exhibit Number Five. Is that an exhibit that you prepared?

A Yes, it is.

Q And this is on legal size white paper. It's an exhibit that has five legal pages to it?

A Yes.

Q And it's a tabulation of what, Mr. Roe?

A It is a tabulation that identifies alphabetically by operator and under that alphabetically by well name, all wells or locations that are within the Gavilan Mancos Pool as of the current date.

It identified their location, the date that they were completing or the status of the location, and also the first month the well was placed on production.

Q Without going into detail, Mr. Roe, take us from left to right across the tabulation and tell us how to understand and read the display.

A Okay. Well, if we could just take a for instance, and because it is the first well on the list we'll use Amoco's Bear Canyon Unit No. 1. It's located in Unit G of Section 15 of Township 26 North, Range 2 West.

The completion report filed with the state showed that the well was completed on July 30th of 1987 and the -- from the production records it began producing in August of 1987 and for the most part, the month of first production is intended to represent the month that it was placed on production and sustained production. If it produced one month and then was shut-in for a long time, I more than likely would present the month that it resumed producing after that long shut-in period.

The -- in fact the next column would be what I believe to be a representative test from this well during the first days of the production test period, which covered July through mid-November of 1987, and so the Bear Canyon Unit No. 1, again, this is not an average from that period, it's what I looked at and chose to be a representative test. I feel that 341 barrels a day, 133 MCF a day, which results in a gas/oil ratio of 390, would be representative based upon the information that I had available.

The next column identifies what I -- at least my belief, the spacing unit, and within Gavilan there are several options, which above the -- right under the heading identified with the letter "A" is representing a spacing unit of 640 acres, which is the current spacing.

The letter "B" would identify spacing units that were developed on 320 acres, which was the effective spacing unit during the temporary pool rule period, and the letter "C" is -- identifies wells that are along the western edge of Gavilan in an area that the Commission has spaced, basically a 310-acre spacing unit, plus an irregular sized section which results in approximately a 505-acre unit.

Q The next column tabulates the production for the high period, test period?

A Well, what it does, is it reflects whether or not I feel that these wells were limited by production allowables during the high rate of production, and I would indicate a well as being restricted by allowable with an "X". The dash would indicate it was not restricted.

Q So, if we apply the high production rate as the limiting allowable and we follow down through each page of that display, do we find any of the wells or any of the operators that have an "X" in the column?

A No. There, in my opinion there were no wells that produced at rates that were restricted by allowables during the high rate of production period.

Q When we look at the last two columns, what is indicated there?

A It would be a similar analysis of the second phase of the production test, but reflecting whether or not the well produced with an allowable restriction during that second phase, and whether it's restricted by gas or oil, you could see I've indicated with an "X".

Q Let's look at the subtotals. Under Amoco they have six wells. We get to the far right column, that represents the gas production.

If the gas production in the well was sufficient enough to be restricted by the gas limitation, then there would be an "X" in that column.

A That is correct.

Q For Amoco we find none.

A Right.

Q For Dugan we find none.

A That is correct.

Q When you turn the page and look at Hixon Development Company you find none.

A Yes.

Q When you look at Mallon Oil you have 5.

A Yes.

Q Meridian has 3.

A Yes.

Q Merrion Oil & Gas has none. Mesa Grande, out of 12 has 3.

A That's correct.

Q Mobil out of 6 has 2.

A Yes.

Q Reading and Davis out of 2 has 2.

A Yes, Reading and Bates would have 2.

Q When we look at Sun Exploration and Development Company, out of their 28 they would have 16 wells that would be restricted at the lower allowable rates.

A Yes, and I would point out that there are no wells that are restricted by allowable. It's the gas allowable that is the restriction, which -- which is the distinction between there being a dash under the oil column and an "X" under the gas column

And just for easy comparison, the allowables during those periods are again reflected at the top of the column.

Q What is your principal conclusion from Exhibit Number Five, Mr. Roe?

A Well, pretty much that there are no wells within Gavilan, at least during the high rate of production periods, that were affected by the gas or oil allow- ables. Out of the 74 wells there is 31 which represents approximately 42 percent of the total that will be limited by the current allowable, which to me represented there's 58 percent that aren't even limited by the current allow- able.

MR. KELLAHIN: Mr. Chairman, we move the introduction of Exhibit Number Five.

MR. LEMAY: Exhibit Five will be admitted into the evidence, into the record, without objection.

Q Mr. Roe, have you taken that information from a study of this particular testing period and drawn any comparisons in terms of the relationship between which operators are benefited and which operators are not benefitted if the higher test allowables become the allowables in Gavilan Mancos?

A Yes, I have.

Q Did you prepare, or cause to be prepared, Exhibit Number Six?

A I worked very closely with one of Sun's engineers who prepared this, yes.

Q Let me direct your attention to Exhibit Number Six and have you identify that exhibit for us.

A Okay, on Exhibit Six what we've done is taken the actual production that was reported on Commission Form C-115 for the periods July, August, September and October, for one period, and compared that production to a form upgraded that would be December through March, December '87 through March of '88, and then we basically converted the production during the first production phase, any individual operator's total production as it relates to the pool total production in the high rate period and then we've taken a look at that same percentage of the total pool production in a low rate period, and the numbers you see on this graph represent the difference that an operator would have of total pool production in the high rate period as compared to the low rate period.

Q When we look at the vertical scale on Exhibit Number Six and we find the zero point on the vertical scale, what is represented by the zero line?

A Zero would reflect that an operator had the same percentage of the total pool production during the high rate of production period as he did during the low rate of production period.

Q And Gavilan Field is the Gavilan Mancos Pool?

A Yes, it is the Gavilan Mancos as identified by the state records.

Q And if an operator's share of production from the Gavilan Mancos Pool falls below the line, what does that percentage indicate?

A It would reflect that they actually during the high rate of production compared to the low rate of production, they would have 3.13 percent less of the total pool; for instance, Sun during the high rate of production would -- their -- their production would account for 38.84 percent of the total pool production, where during the low rate of production they would account for 41.97 percent of the total.

So if we go to the high rate, there would be a reduction in their percentage of the total pool of 3.13 percent, or the difference of those two splits.

Q When we go to Dugan, what happens with Dugan's share of the production from the Gavilan Mancos Pool?

A Well, in this particular case we're on the same side as Mallon is, and we -- we benefit from the high rate of production.

Q When we look at Hixon's share of production what happens to Hixon's share?

A They actually would be 6.05 percent less at the high rate than they would be at the low rate.

Q When we move to Mallon Oil Company's share of production, what happens to their share of the production?

A He would actually gain 21.23 percent of the total pool production during the high rate -- or did gain, I should say, not would gain -- the high rate he produced 21.23 percent more of the pool production than he did at the low rate of production.

Q How many wells does Mallon Oil company have out of the 74 wells in the pool?

A Of the 74 wells that are completed for production, Mallon Oil operates 7 of them.

Q That's about 9-1/2 percent of the wells in the pool?

A Yes, sir.

Q In terms of share of the reservoir on an acreage basis, what percentage of the reservoir does Mallon Oil Company have?

A The acreage that would be -- and this is a real simple surface acreage comparison -- that he would have approximately 8.1 percent of the acreage within the productive area of the Gavilan Mancos Pool.

Q And at the high rate of production, if that becomes the allowable rate, what share of the total pool reserves would Mallon Oil Company capture?

A Well, the percent of the pool production that he did produce during the high rate of production was 29.5 percent.

Q When we go to Meridian, what happens to their share of pool production?

A Well, Meridian would be the only other operator to benefit during the high rate of production versus the low rate, and they actually increased their percentage by .49 percent.

Q And when we look at Mesa Grande's share?

A Mesa Grande takes a reduction in pool total production, as well as Mobil and Reading & Bates.

MR. KELLAHIN: Mr. Chairman, we'd move the introduction of Dugan Production Corporation Exhibit Number Six.

MR. LEMAY: Without objection the exhibit will be entered into the record.

Q Mr. Roe, let me direct your attention now to three small displays. They're on letter size white paper. They are Exhibit Seven, Eight, and Nine in the package. They are plats of Gavilan Mancos Pool and surrounding area.

Would you start first, sir, with Exhibit Number Seven an identify that exhibit?

A Okay. Exhibit Seven would be the map that we have identified with the green and the orange -- orange circles, and what is intended to be presented on this is nothing more than a visual -- some thing to look at to see where during the initial test period of the production test, which was a high rate of production, I feel that these green and orange dots reflect wells that did have an increase in the oil production during that period. Now, when I say "increase", I mean with respect to what they were producing before the period and the rate with respect to what they produced during the second phase of the production period.

The green dots, there's 15 of them, reflect wells that did exhibit this decreasing gas/oil ratio as they experienced an increase in oil production.

The wells that I've colored with an

orange are 7 wells that had the increase in oil but they did not reflect the decrease in gas/oil ratio. Their gas/oil ratio continued to incline or actually maybe a little steeper than was exhibited prior to going to the top of the high rate.

Q In Mr. Weiss' analysis he found some 46 wells that were characterized as having some potential affect at a higher rate. You've taken that number and reduced to 22 and then among the 22 have analyzed it further and divided it into the two categories. We have 15 of one group and 7 of another?

A Well, basically that -- that's a fair comparison, although that's not exactly what I've done.

Q My question is when we look at the 15 wells that are shaded in green, are those wells the wells, and the only wells, that you see in your analysis that appear to benefit by having a lower gas/oil ratio, a higher oil rate at the higher allowable period?

A That is correct.

MR. KELLAHIN: Mr. Chairman, we move the introduction of Dugan Exhibit Number Seven.

MR. LEMAY: Dugan Seven into the record without objection.

Q Mr. Roe, let me direct your attention to Exhibit Number Eight, sir. Would you identify and describe that exhibit for us?

A Exhibit Eight is -- is -- that's the exhibit that we have 3 different colored dots on. There's the red, yellow and blue.

On this exhibit we are trying to show some other changes that occurred during the high rate or production, the initial phase of (unclear).

In red we've identified wells that actually exhibited a decrease in oil rate during this period of time, and bearing in mind now, when I say "decrease" I'm looking at what happened to the oil rate with respect to before and after the high production period.

There are 23 wells that actually a decrease in oil rate during the high rate production test.

In yellow we're trying to show which wells had an increase in gas production and there are 31 of those.

In blue we are trying to show which wells, where they are with respect to the reservoir, that had -- that showed a decrease in production during the high rate of production and there are 21 wells that I believe looking at the production data exhibited a decrease in gas production.

Now, again, I'm trying to be real careful that we're not comparing producing days or volumes.

I'm trying to relate the wells ability to produce in MCF per producing day.

MR. KELLAHIN: Mr. Chairman, we move the introduction of Dugan Production Corporation Exhibit Number Eight.

MR. LEMAY: The record accepts it without objection.

Q Mr. Roe, I direct your attention to Exhibit Number Nine. Would you identify and describe that exhibit?

A On Exhibit Number Nine, this would be the last map and the circle are colored in purple on this map, I have presented here wells that I feel exhibited a lower ability to produce after the high rate of production than they were exhibiting prior to the high rate of production.

Now this is a little interpretive because if the well was on a production decline prior to the high rate of production, what I'm comparing it to as it comes back on production at the lower rate, the second phase, is not exactly the same rate that it was producing prior to the test, but the rate it would have produced at had it continued to decline at the trend established prior to the test, and so these are wells that I feel their production decline, or ability to produce, changed as a result of having the high or the initial production phase.

MR. KELLAHIN: Mr. Chairman, move the introduction of Exhibit Number Nine.

MR. LEMAY: Exhibit Nine into the record without objection.

Q Mr. Roe, let me direct your attention to Exhibit Number Ten. That is the package of well production histories on legal size paper.

Would you identify that exhibit for us, Mr. Roe?

A Exhibit Number Ten is a compilation of production statistics, production curves, and -- or plots of production data, and when available I've included some pressure decline data that I had on those wells.

It consists of 82 pages and I apologize, I did not number any of the pages, so wading through this is not going to be as easy as it should. The wells are in this package alphabetically by operator and by well name.

Within this package there's 27 wells of the 74. While we're getting set up, because the production curves when we'd reduced them to the scale we had to in order to make them reproducable easily, some of the information became not as clear, and so out of the 27 wells that are within this package, we have blown up or taken advantage of the larger scale to try to talk through some of the things that we see.

We don't plan to talk about all 27 wells, although the general comments and the information we'll talk about on any one well is there for all wells.

MR. KELLAHIN: Mr. Chairman, at this time we move the introduction of Exhibit Number Ten.

MR. LEMAY: Exhibit Number Ten accepted by the record without objection.

Q Mr. Roe, let's go to the first blow-up from Exhibit Ten information and look at the Mallon Oil Company Howard Federal 1-8 Well.

A Okay, that would be the second well in this package.

Q What is the conclusion you reach from analyzing the information from the Howard Federal Well, Mr. Roe?

A Okay. This particular well is one that I -- that would have been shown on the previous three exhibits and it would have -- this well location would have been colored yellow, indicating that the -- it did have an increase in gas production during the high rate of production test, which on this curve I've identified the gas with the green curve and the oil with the red curve and the gas/oil ratio with the blue line and what I reflect here is just so you can see what was necessary for me to say this well did have an increase in gas production and when you compare the -- basically the July through November data in green to what we had before, now, this particular well, we have some awfully misleading results when we compare July, '87 to -- the high production period to immediately before, because this is one of the wells that pretty much the first six months of '87 was -- was restricted to a maximum gas rate of 100 MCF a day by the OCD because leading into 1987 it was pretty seriously over-produced as a resulting of some production prior to 1987.

And so, again, comparing the gas/oil ratio during the high production phase to the six months preceding will give you some misleading numbers because at the lower gas rates that were required of this well, it would -- did not efficiently lift oil from the reservoir.

You can also see the fact that the oil production jumped up pretty dramatically, which would explain why this well should have been colored green on Exhit Number Five because it also had an increase in the oil.

Now this is one of the wells that I feel suffered some -- or I call is suffered, It reflects a reduction in its ability to produce during the second phase of the production test. For instance, the December, January, February, March data on the oil and the gas would reflect much lower rates than -- and again this is a little hard to compare because immediately preceding the test the well was not producing at the representative allowable for the Gavilan Mancos Pool. It was being restricted to a maximum 100 MCF a day Mallon total production, but if you can take a look at the rate of production, say, during, oh, January, February and March, and admittedly, what we're plotting on this curve is total barrels of oil, what, say, January, the well actually only produced six days for a daily average of 118 barrels a day, and it produced, or it probably had the potential to produce at quite bit higher rates than that prior to the initial test period.

Q Let's go on to the next well, Mr. Roe.

A Okay, that -- that would be the second -- well, there's one other piece of information in this 1-8 that's not on the extended curve, but it is in the package of information that I think is important to know, and there are several wells in that package that have this information. I've presented 2 pages of pressure data that was collected in the Howard 1-8 during the February pressure test.

My purpose in including some of this pressure data was not to tell you anything about the well other than it's communicated with something else in the reservoir, and the information on this sheet that tells me that is basically the last two pressure points on this tabulation. Say, for instance, the well had been left shut-in after the pool was brought on production following the shut-in period at a shut-in time of about 64 hours on this shut-in time, all wells within the Gavilan Mancos Pool were returned to production and at 25 hours later this well started showing a pressure decline. Now, admittedly, it's only 2 pounds but considering that it had at 982 pounds from basically 76 hours through 87 hours, I feel probably the 2 pound drop reflects that 25 hours after the pool was placed on production, this well, even though it was still shut-in, started showing up some effect of something going on somewhere else, and all that I intend to show with that pressure information.

Q Let's turn to the Mallon Well, it's the 1-11 Well?

A Yes.

Q Howard 1-11.

A That would be the third well in this package.

Q What are the major conclusions you draw from an analysis of information from this well?

A First of all, what category does this well fall into?

A Okay. Well, basically this is a well

that also experienced an increase of oil production and an increase in gas production, and therefore, with a little good luck it was colored yellow and green on the Exhibits Number Five and Six, and I feel probably reflects a significant drop in its ability to produce at the second phase of the production compared to its ability to produce prior to the high rate of production during the production test ordered by the Commission.

So it also was a purple dot on Exhibit Number Seven and --

MR. DOUGLASS: I'm sorry, I didn't get the well that you're talking about.

A This is the Howard 1-11 Well.

MR. DOUGLASS: 1-11.

A Yes, sir.

Q I believe you're looking at Exhibits Seven and Eight rather than Five and Six?

A Well, yeah. Yes. (Not clearly understood) production curve on a well operated by Sun and again the lack of having page numbers is going to probably show up here, but this is the Dr. Daddy-O, and it is on into the package about midway, and if you'll -- the wells are alphabetically, so what you need to do is find basically Sun as the operator and then under Sun it would be right behind the -- the second well in Sun and it follows the Beek's

Babbit No. 1.

Now, before we go to the production curve, the main reason that I included the Dr. Daddy-O as a well, not only did it reflect some changes going on in the production curve, but it also -- I had some pressure data that I've included that tells us a little bit about this well's communication with the reservoir.

For instance, the first sheet that is the section with the Dr. Daddy-O would be data that we recorded, and again, Dugan Production actually did this work with McHugh as the operator just prior to Sun purchasing this well. Early in the -- or late in June of 1986 we had a pressure bomb on this well and this well did not really commence producing under a sustained basis until September, 1986, so this is at a point in time that this well was reflecting a production decline not as a result of production in this well but as a result of production from somewhere else in the reservoir, and the pressure recording equipment that we were using to record this data with was a very sensitive bellows-type pressure bomb that has the accuracy and ability to measure the pressure implements we're showing here, so there should be no question as to this being actual data, it's well within the range of the tool.

And what I point out is, on the first page there was a period that 1.9 psi per day was the rate of pressure decline in this well with this well shut in.

On the second page I've got some additional data that shows how well this well responds to something else in the reservoir. I have not, for the purpose of this hearing, attempted to explain of these changes although you can see that we, in the latter part of June and early part of July, the rate of pressure change actually approached 8.2 pounds per day. It later takes a change of 1.9 pounds per day, and again, presumably, there's something going on somewhere in the reservoir that's causing these changes.

So what happens conversely is if we produce this well at a high rate versus a low rate, it is also going to affect something somewhere else in the reservoir here. We're just trying to draw communication with the reservoir here.

MR. DOUGLASS: Could you repeat those declines in production? I can't read them on my copy here.

A Let me -- the copies, you must just have a bad Xerox. Let me read them first and then -- on the first sheet which just has a very -- it would be for the old, 23rd, 24th and 25th of 1986. That was 1.9 psi per day.

During the -- on the second page, the

time frame July 8th and 9th, the rate of pressure decline was 8.2 psi per day.

The initial rate of decline, say, July 9th -- or 10th and 11th, so that was actually July 9th and 10th, the well was declining at 8.2 psi per day. Now what makes that a little confusing is we have a scale change there. Really this -- this middle part of the curve, with respect to this, it's just a continuation of -- of this curve.

MR. DOUGLASS: I can't read this also at the left up there. What number should be in that, 8.2?

A Yeah, 8.2 psi per day would be the first. If -- if you --

MR. DOUGLASS: I think that's what you said.

A Anyway, so 8.2, the first part of this production graph, and it continues on the second part with 8.2 psi per day, and then something happened in the reservoir between July 9th and July 10th, and it looks like the early part of July 10th, and the rate of pressure decline at the Dr. Daddy-O decreased to 1.9 psi per day.

So again, nothing happened in the Dr. Daddy-O. That well was shut in and we had a pressure bomb in the hole; we were just observing what was happening to the pressure in this well, because of something else in the reservoir.

And this last section of the curve, again the pressure was declining so much that we actually had to have the scale -- this part here should really be down here, but we've just put a new scale on it and so this point is a continuation of that curve, just as this point was a continuation of that curve, and you can see, the 1.9 psi per day is a continuation of the 1.9 established here, and similar to the 1.9 that we saw nearly a month earlier, and the only point we're trying to exhibit with this is -- is that 8.2 psi per day is a tremendous rate of pressure depletion, especially when this well was not -- not producing.

Q What does that tell you, Mr. Roe, as an engineer in terms of the correlative rights among owners and operators of wells within Gavilan Mancos itself?

A It tells me that the -- that any one well's ultimate recovery from the reservoir is going to be totally dependent upon its ability to produce reserves competitively from the reservoir, and they could very easily be violated if for some reason or other, whether it's allowables or mechanics or anything, if you shut a well in, that point of the reservoir is going to continue to produce as we -- we've displayed with these two exhibits. That rate of pressure decline correlates to production and not production from the well, but from that point in the reservoir moving somewhere else in the reservoir, resulting in that pressure drop. So that number can be converted -- I won't say that.

Q Let's go on to the next display.

MR. DOUGLASS: I'll ask you again.

A I'm sure you will.

Q The next well to comment on, Mr. Roe, is the McHugh Well. It's now Sun. It's the Homestead Ranch No. 2 Well, so in the table of well histories, if we go to the Sun section --

A Well, did we want to actually look at the production curve on the Dr. Daddy-O for a minute? Okay. The Dr. Daddy-O was one well that actually showed a drop in oil production during the high rate of production, and also an increase in gas, which basically resulted in an increase in gas/oil ratio during the test.

Q The Dr. Daddy-O Well will appear on 7, 8 and 9 in what colors?

A Red and yellow.

A All right, let's go to the Sun Homestead Ranch No. 2 Well, Mr. Roe.

A Okay. The Homestead Ranch No. 2 will be just a little bit on into the package behind the Dr. Daddy-O.

Q Into what category does this well fall when we look at displays 7, 8 and 9?

A This would be a well that I felt exhibited an increase in gas production and sustained a reduction in its ability to produce following the high rate of production test. It would have been colored yellow and purple on the -- the maps.

Now, again, prior to looking at production curves, we've got some pressure information in this well that basically is -- is the curve, again, I wish I could identify page numbers, but this is the page I'm talking from and once more it is a presentation of what's happening to the pressure in the well with this well shut-in.

Again, this well was not producing when we were recording these pressures and the pressure decline you see in this well is because of production somewhere else, and early in the survey it is .24 psi per day; something happened. I just picked out two wells that were placed on production that may explain it. The production decline approached a 2.2 psi per day. A little later I see the pressure starting to build up and I have also identified an event in the reservoir which was the shut-in of two wells that probably explains that pressure increase, the point being that this is very well pressure communicated to other points in the reservoir.

The production curve that we see that again is just intended to show that during the high rate of production the well did have the increase in gas production which is the green line. It basically did not exhibit, you might say, into July and August was an increase in oil, the red curve, but the last two months actually show a drop in oil and it shows a drop in oil with the gas still up and the result is the gas/oil ratio in this well actually up pretty dramatically during the high rate production test; the inference being that with the pressure communication we see on the previous exhibits, the increased gas production here may explain some of the decreases in gas production somewhere else.

Again, I have not made an attempt to correlate where in the reservoir these changes happen, but with the pressure survey I feel fairly certain that they are happening somewhere.

Q Let's turn to the last display out of Section 10 and have you identify for us the Janet No. 2 Well, formerly a McHugh Well and now Sun, we'll find that under the tabulation of wells for Sun Exploration?

A Yes. That's just a couple of more wells into the package following the Homestead Ranch No. 2, and this would be the Janet No. 2. On the previous maps that would have been identified with the red, yellow and purple dots, which indicates that this well did have a decrease of oil; did have an increase in gas during the high production period, and upon return of the well to production at the low rate, had a negative effect on its ability to produce, and that, you can see -- now at this particular well the gas/oil (not clearly understood) highlighted in blue, you can see this gas/oil ratio actually started to incline quite a bit before the September allowable reduction, so I feel this may be a good example of -- of natural reservoir performance and wasn't complicated with the fact that we an allowable reduction (not clearly understood) to it.

Q Mr. Roe, having studied the Gavilan Mancos production for years, having analyzed the information from the bottom hole pressure tests, the high rate and the low rate production information, do you have a recommendation to the Commission as a petroleum engineer actively involved in the Gavilan Mancos, as to how in the absence of pressure maintenance the operators in Gavilan Mancos can operate that pool for the remaining life of that pool?

A In the absence of the unitized effort, my feeling is that we have to have some sort of control on allowables in order to protect correlative rights of all operators within the Gavilan Mancos Pool.

Q Do you have a specific recommendation to the Commission with regards to how they might implement rules that are flexible enough to allow those high capacity wells an opportunity to produce more oil without adversely affecting the correlative rights of those wells with lesser capacity that are connected with the higher capacity wells?

A Yes, I have.

Q And what is that recommendation?

A Well, from the standpoint that we do see some wells making a more efficient use of the reservoir energy at the higher rate, in other words the gas/oil ratio (not clearly understood), it is my recommendation that in the event an operator has that belief, that he be allowed to produce -- that the pool rules be modified such that we would -- it would provide an operator basically an exception to statewide Rule 502, Subsection 2, and we would propose that any one well would be allowed to be -- to produce at his -- whatever rate he desires until he's four allowables over produced, and at that point he would be shut in until he balances his allowable. That way he would be able to make more efficient use of the reservoir energy and minimize the impact upon correlative rights.

MR. KELLAHIN: Pass the

witness, Mr. Chairman.

MR. LEMAY: Mr. Douglass?

MR. DOUGLASS: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. DOUGLASS:

Q Mr. Roe, you've mentioned several times the term correlative rights. How do you determine correlative rights, or what is your standard for correlative rights?

A I use the guidelines as I understand them, and that's that each lease and working interest owner, royalty owner, should have an equal opportunity to recover the reserves and the reservoir energy that is attributable to that parcel of land.

Q Now when you say reserves, what do you mean by that term?

A That would be the oil and gas in this particular instance that would be actually under that tract of land, there to be produced.

Q Have you made such a determination with reference to the tracts in the Gavilan as to what you call the Gavilan Mancos Pool?

A There has been a tremendous amount of

effort in the Study Committee to establish the reserve distribution in the pool and although we didn't as a committee and I have haven't as an individual, come up with, like, by section a breakdown of the reserves, I think it was our general consensus, and it's certainly my belief, that there may be some variation but not a significant variation of oil in place and recoverable reserves throughout the area we're talking about.

Q In other words, you haven't got a figure that you can give us with reference to various sections but you have a rough feeling that you think there are about equal per section.

A That's my feeling, yes.

Q Now, as a reservoir engineer are you recommending to this Commission that they should prorate an area based on the poorest wells that you have?

A No, sir.

Q What should be the standard for determining, then, what -- how an administrative body should prorate an area?

A Well, it's my feeling that probably it should affect the majority of the wells in the field.

Q Are you saying that the standard should be at least an average or better than average well to -- to determine the rights of the parties?

A No. I think I meant that it should reflect, if there are 74 wells in the pool, that at least half of them should be affected by whatever, or benefited by whatever, we're talking about.

It doesn't make sense that a set of parameters, whatever they are, would only affect a few wells, or at least to me it doesn't make sense.

Q Would -- would the reserves that you're talking about be directly proportional to the oil in place that you have under a tract?

A Yes.

Q I believe you put a graph in that shows, I think it was you, a graph that had the pressure zones, was that Exhibit Three? Two? I'm just trying to get to -- or Four. I believe it was Exhibit Four, is that right?

A Yes, that was Exhibit Four. It's a plot of pressure versus cumulative production?

Q Yes, sir, thank you. And what you show on that, I believe, if you look at your book, that what you call the Gavilan Mancos Pool has produced 4.017, I think, million barrels of cumulative oil, is that approximately right?

A That would be approximately right, yes, sir.

Q Now how much of that production or,

excuse me, did I understand you to say that the wells in the pressure maintenance expansion area, what we call the expansion area, came on in January of '85?

A If I said that I didn't mean they all came on. That was about the time that the first well in the expansion area was placed on production but because that development occurred not gradually, but it didn't all occur at once; they actually were coming on production all the way through, well, into 1987.

Q So up to January, 1985, then, there was no production in what would be called the expansion area.

A Not any that I picked up as being significant production, no.

Q And if I look at your Exhibit One here, I can see in January of -- perhaps you could tell me when you think the -- I can see in January of -- of '85 the cumulative production had been about 643,000 barrels from Gavilan Mancos, is that right?

A Yes, sir.

Q And by the end of -- would you say by the end of '85 that you'd gotten your wells on production in the -- in the expansion area?

A Some of the wells were on production but -- but not all of them.

In fact, I think really only three wells from -- that are located in the expansion area were actually placed on production during 1985.

Q Okay. Well, then, would the -- would you say that essentially, that it's your position that essentially the wells in the expansion area didn't affect the Gavilan area as far as production was concerned until the end of '85?

A I can't say that. I feel the expansion area is in communication and so it's -- I think there may have actually been some -- some effect by putting three wells on in 1985, although I -- that's just my feeling.

Q Would you say then about mid -- if I use the -- I want to try to get a production figure that occurred out of the Gavilan area that hadn't been substantially affected by the production out of the expansion area.

A Well, I think probably January '86 would be a number we could say hadn't been a substantial affect.

Q All right. Let me start over, then, with the chart here.

And just in January of '86 I see that the area that we're talking about, let's use December of '85, had produced 1.520-million barrels, is that correct? In other words, if I go to your graph that you have --

A Yes, sir.

Q -- and go down to the cumulative production at that time, it would be about 1.5207.

A Yes, sir.

Q And your total production that you have to date is 40176, is that right?

A Yes. I think that's in thousands of barrels.

Q I understand. If I subtract correctly, looks like since the expansion area went on production Gavilan has produced 2. -- roughly 2-1/2-million barrels.

A Yes, sir.

Q And do you know how much the expansion area has produced since it's been on production?

A I don't have those numbers, no.

Q Okay.

A Those numbers are available in our Exhibit Number Two.

Q Right, I understand that and I'll get my people to add them up.

A We just have not actually added them up.

Q I was going to just check, they get 1.603-million barrels of cumulative production since the expansion area went on. 1.603-million, so from the time the expansion area went over, it was -- if you'll accept the 1.603 subject to check, it produced 1.603- million bar rels and the entire Gavilan Field produced about 2-1/2-million.

A Yes, that sounds reasonable.

Q Do we have in the record some oil in place figures for those two areas?

A In the -- since 1982, when we first started talking about this area I suspect there are several entries into the record of oil in place.

Q About this hearing here? How about Mr. Lee's figures on -- that he had on his -- his map?

A I, quite honestly, when Mr. Lee was presenting his testimony, I was thinking about mine.

Q Okay. Well, I understood from his oil in place figures for -- we went to Area 1, 2, 3, 4 and 5, and I understood Area 5 -- Area 3 was the oil in place for the -- what is called the expansion area. If you'll accept that --

A Well, --

Q -- does that look like the expansion area to you?

A That is, yes, that -- I know that to be the expansion area. I might qualify now. I wasn't greatly involved with what Mr. Lee did, but --

Q I understand.

A -- I think it was his assignment to give us a general idea as to what happens. I don't think he was asked to do a model study of the reservoir.

Q Okay, but his study shows there's 19-million barrels in place in that expansion area, is that correct?

A I don't know if there is.

Q Well, do you want to look at the figure? It says, "OIP 19.0 MMSTB."

A Well, I'm sorry, Mr. Douglass, I can't see that from here and I --

Q Okay.

A -- was not --

Q I understand.

A -- paying attention when he was telling us.

That's what it says, yes, sir.

Q Well, while you're looking, what's the oil in place for the Gavilan Field according -- the Gavilan Pool, according to Mr. Lee's figures?

A Okay, Mr. Lee's figures represent the oil in place as for the pool, I would say he's got in one tank 17.1 million stock tank barrels and 28.2 million stock tank barrels in the western portion.

Q Does that add up to 45.3?

A Subject to check, yeah. Can't see it

again.

Q Did I detect when you put on your exhibit with reference to Mallon's percentage of the production during the normal rate time with an increase of 21.3 percent, did you intend to infer that you thought that was not fair?

A Yes, sir.

Q Do you have a calculator?

A I do.

Q Can you tell me what percent of the expansion area oil in place has been produced?

A I, yep, but I will comment, you know, we're looking at the expansion area, a large number of those wells didn't actually come on production until mid-1987, so what comparing is -- five or six months worth of production from those wells to two to three years of production for wells in the Gavilan.

Q Well, I'm trying to -- I think I'm comparing all the production from -- that's the total cumulative production from the expansion area, what I've got here, not just the last four or five months.

A Yeah, but my point was that not all wells were producing during that period of time but the cumulative --

Q In other words, you could have produced more if you'd gotten the wells on earlier.

A Correct.

Q Yeah, that's true of any reservoir, if you'd gotten the wells on earlier, you could have produced more oil to a certain period of time.

A You're right.

Q Okay, can you give me a percentage?

A All right. 7 -- using 19?

Q Using 19.0.

A Okay, that would be 8.4 percent and if Mr. Lee's right, the expansion area has produced 8.4 percent of its original oil in place since those wells have been on production.

A Yes, sir.

Q Or the equivalent of it. How much during that same period of time did the Gavilan Field produce? 2.4969 divided by 45.3.

A 5.5 percent.

Q 5.5 percent.

A That's subject to check, also.

Q Oh, I understand that and I'm sure you will.

Now, so the Gavilan Field during that same period of time, essentially, produced only 5.5 percent of its original oil in place.

A Which is probably all, approaching all that you would expect from a primary depletion type reservoir.

Q Well, but during that period of time we had restricted rates in Gavilan, didn't we?

A A very small part of that time, yes, sir.

Q Well, from August of '86 to present, except for four months, you consider a small period of time.

A No, I'm sorry, you're right.

Q All right, sir. Now, if -- comparing the 5.5 percent to the 8.4 percent, how much greater is the 8.4 percent than the 5.5 percent?

A Okay, again supposing that I've made no errors, it's 52.7 percent greater.

Q 52.7 percent. Now awhile go you said it wasn't fair for Mallon to get 21 percent more, didn't you?

A Well, 21 percent more of the Gavilan reserves, yes, sir.

Q Do you think it's fair for the expansion area to get 52.7 percent more of its reserves than Gavilan did?

A Well, yes, because I don't see that the comparison is a realistic comparison. What you're comparing is -- what we really need to compare is rather than

19-million barrels of oil, that is -- if that's the number from him, I am not sure that that is a number I would agree with, although I don't have a better number to give you when you asked for one, but I think the number of oil in place that you really need to use to compare recovery from the expansion area would be basically the oil in place in the unit because as I see the expansion area, it's the withdrawal area for the unit that is injecting gas up structure and producing oil down structure.

Q Well, under the -- under the theory that opponents have here, that this is all one reservoir, or under the theory the Proponents have here, that there's a barrier that separates the expansion area from the rest of the unit, that the -- under either one of those the expansion area as a unit rather than -- I don't mean a unitized, but as a comparison area, has produced 53 percent more of its original oil in place during the same period of time that Gavilan has.

A Well. there's reasons for that.

Q All right, sir, and one of the reasons is the restricted rates, isn't it, in Gavilan?

A Well, primarily it's just a lower gas/oil ratios that result because of the pressure maintenance in West Puerto Chiquito, and so they don't have near the rate restriction that results when you have the reservoir depletion that's occurring in Gavilan.

Q Well, are you saying, then, that the Commission should set rules that -- that permit an area to get 52-1/2 percent more of their oil in place during the same period of time?

A No, that -- my recommendation today is the same as it was in several of the earlier hearings, is that we ought to unitize Gavilan, shut-in the high gas/oil ratio wells and then we would be enjoying the same benefit the unit has.

Q Well, let me ask you, is one of the factors that's used in unitization among the operators cumulative production?

A In a conventional reservoir but our Engineering Study Committee efforts that Mallon had people involved in and all operators had people involved in, we all agreed that the cumulative production in this kind of a reservoir would be an unrealistic parameter because of the communication that exists and as I exhibited or displayed in my Exhibit Number Ten.

Q What you're saying is that this expansion area, when it produces 52.7 percent more of its original oil in place, it's able to drain the Gavilan area, isn't it?

A So far that hasn't been the case and

it's my understanding that Mr. Greer is actually willing, and this is something he can do in the unit area, and I'm not sure how Gavilan is going to do it because they aren't unitized, but he's will to work so that we'd try to maintain a zero pressure differential across the boundary. It's my understanding that the pressure to date has actually had a pressure gradient from the unit into Gavilan, and that's primarily why, as a working interest owner in the Canada Ojitos Unit, we were very excited about getting the wells drilled in the expansion area, to minimize that flow from Gavilan into -- or from West Puerto Chiquito into Gavilan.

Q But that boundary that you're talking about there, when you started to produce in the expansion area, and you produced 52.7 percent more of your original oil in place compared to Gavilan, that oil was moving from Gavilan to the expansion area, wasn't it?

A No, sir, I don't believe that at all.

Q Well, how could it not?

A How -- how could it? It has to have a lower pressure -- in order for oil to move from Gavilan into West Puerto Chiquito. The pressure would have to be lower in West Puerto Chiquito anywhere than it is in Gavilan, and that has not been the history.

Q All, it would have to be lower across

this boundary line, wouldn't it? Isn't that where the oil is going to be moving across?

A No, it would have to be lower to the right of the boundary.

Q Right, and you're saying that the pressure has never been lower east of the boundary line?

A No, I -- I didn't mean to say never. I do feel that since there's been development in the expansion area, the pressure in what you call the expansion area has been higher than the pressure in Gavilan.

Q Well, then you're saying the pressure east of the boundary line as it now exists has never been lower.

A No. I didn't mean to, if that's the way it came out, I didn't mean to say that. I think there was a time before any development occurred in Gavilan, that's before Well No. 1, the Gavilan No. 1, I think probably there might been some migration from the Gavilan into West Puerto Chiquito.

Q After production started in the expansion area, has the pressure been lower east of the boundary line between Gavilan and the expansion area?

A I would guess, before I could give you an exact answer, I would have to look at all of the data.

It's my feeling that generally the pressure in the expansion area has been higher than the pressure in Gavilan.

Q Are you -- so your best opinion is that the pressure has always, since production started in the expansion area, been higher in the expansion area than it has been in the Gavilan, theoretically?

A Yes, that is.

Q But you said you needed to check the data before you'd be satisfied.

A Yes. When you say "ever" and "all" I would have to check.

Q Well, I'm -- I'm trying to get it limited to an area that you could check.

MR. DOUGLASS: This is a convenient time to stop or I can continue on, whatever you prefer.

MR. LEMAY: No, if it's a good break for you, let's take a break for lunch and come back at 1:15.

(Thereupon the noon recess was taken.)

MR. LEMAY: The hearing will come to order. We shall resume. Mr. Kellahin, have your witness take the witness stand again.

Mr. Douglass.

CROSS EXAMINATION CONT'd

BY MR. DOUGLASS:

Q Mr. Roe, as I understood your presentation, you started off with some general propositions and then you went into your exhibits, and I want to cover just one or two of the general propositions.

I believe you said you didn't see any reason to change the boundary, and that's basically because you think it's all one common reservoir, is that correct?

A Yes, sir.

Q If the Commission finds that the barrier exists where it's been shown by the Proponents, then would it be satisfactory from your standpoint as far as the recommendation is concerned to at least have the same applicable rules as far as production and development, and so forth, are concerned, with regard to the expansion area and Gavilan? That assumes that the barrier is there and that the Commission so finds.

I understand you don't believe that it's there, but if it -- I do think that's a point of contention in this matter and the Commission may very well find that it's there.

A Well, Mr. Douglass, my reasons for

thinking for a minute was we're -- Dugan Production has an interest on both sides of the fence here and there has been a fairly large effort expended to develop on both sides of the fence in a manner that unit lands are protected from drainage, as well as Gavilan side is protected from drainage, and I was trying to decide if moving that line -- now, if there is a barrier, I agree that it probably wouldn't make a big bunch of difference, and that was my dilemma, I suspect it wouldn't make a big bunch of difference if there was a barrier there.

Q Well, it seems to me that the Commission, if they find a barrier is there, has got a choice; either they put the expansion area into Gavilan or -- and call it one pool, or they could leave a boundary there and make sure the rules are the same on both side.

A Well, they --

Q Do you see any other option than that if they find the barrier is there?

A Well, basically the rules are the same on both sides right now, aren't they?

Q Well, that's what I want to make sure.

A Well, it's my understanding that Mr. Greer has actually modified the West Puerto Chiquito Mancos rules to be parallel with the rules regarding development and allowables with Gavilan, but there is no difference right now.

A Okay, I want to make sure that if they find the barrier is there, then as far as you would be concerned, that they keep the current rules in as far as the -- making them the same on both sides of that line is satisfactory.

Q I -- I don't understand why it would be worth all the paperwork necessary to do it. I don't see that it would change if there is -- if there is a barrier there, and the pool rules are the same on both sides of the fence, what -- what would change?

Q I think my -- the answer to my question is yes, but that's all right. I think that I understand that as far as you're concerned, whether they're put in one pool or they're divided, as long as the pool rules are the same on both sides of that line, if the barrier exists, is a satisfactory arrangement.

A Yeah, if the barrier exists, I don't see that there would be a problem.

Q All right. Now, Exhibit -- you put in Exhibit One the production statistics, is that correct?

A Yes, sir.

Q And then later on you said that you thought, looking at the July and August, September and October periods, just looking at those periods might be misleading because of some problems that may have been in May and June of that year, is that correct?

A Yes, sir.

Q All right. Do you have that Exhibit One before you there? And the last three pages, beginning, do you have the monthly oil production being one, two , three, four, fifth column over?

A Yes, sir.

A And in January of '87 was that 81,304 barrels?

A Yes, sir, it was.

Q Now, I believe you said you -- that that might -- that you didn't -- you shouldn't look at December and January of that particular period because you had four new wells to come, but they're on in January, is that right?

A I didn't remember making the correlation between December and January. The two months specifically I was talking about was May, 1987, and June, 1987.

Q All right. Do you -- do you think from January '87 to date was a representative period to look at the Gavilan?

A No, sir, I don't, because during that period some of the very large wells in the pool were actually shut in or restricted in their permissible allowable and so during that period of time the gas that -- what little production they did produce, the gas/oil ratio was high distorted and that will distort the pool's average gas/oil ratio.

Q So you don't think you can look at January '87 through March of '88 to get any kind of idea of what's going over -- on over here in Gavilan?

A I think you have to look at the data. My whole discussion was centered around that you've got to not overlook that we're dealing with a reservoir that is highly communicated and what happens throughout the reservoir affects all -- in other words, the fact that you have a well shut in doesn't mean that that point in the reservoir isn't producing, and although we do not make that point when we're (not clearly understood) the production graphs, following a sustained shut-in for some reason or other a well returned to production quite often returned to production at a level that's less than it was when it was shut in, but along the trend that was established prior to shut-in is primarily because of continued reservoir production.

Q Mr. Roe, do you think January '87 through March '88 is a representative period to look at the Gavilan Field area as far as production is concerned?

A Mr. Douglass, I think that that is the period that some of these larger wells were being restricted to an artificially low gas/oil ratio because of an overproduced status, and that forced the whole gas/oil ratio in the pool to be high.

So if you need me to guess yes or no, I'd say no.

Q You'd say no, all right. Well, let's look at it, even though you don't think it's representative. Do I see from the period of January '87 through March of '88, that every month that you had increased oil production you had decreased gas/oil ratios and every month that you had increased -- decreased -- I'm sorry, let me start over -- increased oil production, decreased GOR?

A No, sir. In fact, let's look at -- let's just pick the high allowable period and let's start with July of 1987. That month we had 99,567 barrels of oil produced. We produced 528-million cubic feet of gas, and the gas/oil ratio was 5303.

Q All right, so we had a 9 -- let's start there, if you think that's a good place to start, did the oil production go up the next month?

A Yes, it did.

Q Did the gas/oil ratio go down --

A Yes, it did.

Q -- in August? In September did the

gas/oil -- did the oil production go up?

A Yes, it did.

Q Did the gas/oil ratio go down?

A Yes.

Q In the next month, from September to October, did the oil production go down?

A Yes, it did.

Q Did the gas/oil ratio go up?

A Yes, it did.

Q Did the next month the oil production go down?

A Yes.

Q Did the gas/oil ratio go up?

A Yes, it did.

Q Did the next month the gas -- did the oil production go down?

A Yes, sir.

Q Did the gas/oil ratio go up?

Q Did the next month the oil production go up?

A Yes, it did.

Q Did the gas/oil ratio go down?

A Yes.

Q And the next month did the oil production go down?

A Yes, it did.

Q And did the gas/oil ratio go up?

A Yes.

Q And that was the period when none of these wells, high ratio wells or low ratio wells, whatever you want to call them, were shut-in because of over-production.

A Yes, sir. You're right. I was looking at some wrong data, but I would point out that we have acknowledged, in fact one of my exhibits did address that some of the larger wells actually showed -- in fact I think it was 22 of them -- did exhibit a higher rate of oil production, and of those 22, 15 of them exhibited a lower gas/oil ratio, which is primarily the reason behind us making a proposal that, if that is the case, we are actually maximizing the reservoir energy and therefore we feel that if we can do that by allowing an operator to produce at higher rates, then we would ask that the Commission allow that but also try to give us some means to protect correlative rights.

Q Well, now, let's see if I understand the two parts of that.

First of all, you recognize, then, in the Gavilan, that if you produce at high oil rates, you produce at low gas/oil ratio and that's a more efficient use of the gas to produce the oil, is that correct?

A Only in some wells, Mr. Douglass, 22 of the 74.

Q Well, --

A There were actually quite a few wells that -- a similar number of wells that had decreased in production during this period of time.

Q Well, when you deplete a reservoir, is the oil and gas production going to go down?

A Yes, but is it fair for them to go down because their offset wells go up?

Q Well, I guess the question of fairness has got to be one that this Commission's got to test. Are you saying that it's fair for another well to produce more oil than another well in the reservoir?

A If the reserves and reservoir energy that that well has a right to produce are higher, then sure it's fair that he produces more.

Q All right, and if you should in these wells -- let me ask this: If you separate -- if this barrier exists, in your opinion what is the drive mechanism for the Gavilan and the expansion area if the barrier is there?

A Well, I'm one of the parties that thinks that we have some gravity drainage and solution gas drive in Gavilan Mancos Pool.

Q All right, you think there is gravity drainage in this essentially flat reservoir over here in the Gavilan Mancos and the expansion area?

A Well, yes, sir. I put gravity segregation within this 600-foot overall Mancos interval that we're producing into the gravity drainage category.

Q That gravity drainage is -- each well's going to have the gravity drainage, same gravity drainage at each location, isn't it?

A Yes, sir.

Q All right, do you agree with -- I think that what I understood Mr. Lee to say is that if you use gravity drainage as the producing mechanism in the Gavilan, you adjust production to what gravity drainage would let you produce, that it would be so low that the wells would be uneconomic. Do you agree with that?

A I agree that the rate of dip in Gavilan is very minor but they still have a fairly significant gravity segregation within the reservoir.

Q Mr. Roe, you do believe that the production from this area that we're dealing with here, that is, the Gavilan area, doesn't come out of just the major fractures, don't you?

A If you're asking if I think there's

large fractures and small fractures in those, well, yes, I do believe that.

Q All right, sir, and you would equate the small fractures to being -- operating just like a matrix, wouldn't you?

A No. Now during the break I did express that the fracture system, it is lesser developed. The microfractures and the small fractures are going to exhibit a different performance than the large fractures but when you use the word "matrix" I have a totally different concept of what happens in the reservoir than I do in a fractured shale.

Q Is the -- is the Davis 3-15 Well, was it drilled in the matrix rock?

A The Davis 3-15 was -- it penetrated the Niobrara and if you look at the electric logs, it looks exactly the same as the offsetting Fisher Federal or Howard 1-8 or Howard (unclear).

Q Well, then it did penetrate the matrix rock as opposed to the major fracture system.

A It penetrated the Niobrara formation just like every well out there.

Q Well, I thought Mr. Greer's theory was that there were these major fracture systems and these tight blocks that sometimes would have as much as an acre or 2 acres in them.

A Maybe even 40 acres.

Q Or maybe even 40.

A Yes, sir, and I --

Q All right.

A -- I subscribe to that theory also.

Q Okay, was the 3-15 drilled in the -- in one of these tight blocks that's 1 or 2 or 40 acres, whatever size?

A I -- that's my feeling, yes, sir.

Q And it did produce oil. The 3-15 did produce oil from that matrix.

A Yes, after fairly major stimulation and I feel fairly certain that because it was the quality well it was that we're not looking at matrix, though, we're looking at the fact that we're dealing with a fairly massive formation and it's in an area that there was a major upheaval back in the early days, and it's unreasonable to think that there's any part of the reservoir that hasn't been affected by this fracturing mechanism.

Q Let me ask you on Exhibit Three, you included not just the Gavilan wells on this pressure survey that you show here, did you?

A That is correct. I included some of the Canada Ojitos wells.

Q You included three wells in the expansion area, is that correct?

A My -- what I included was all of the unit wells that were at a structural position that I could have reasonable certainty in extrapolating the pressures to a datum of +370.

Q And -- and the conclusion that you drew from this, as I understand it, is that during the normal rate of production, what we call normal rate and you called high rate, and the low rate, that you were able to get more oil per barrel of pressure drop.

A Yes, sir, that was my conclusion.

Q Okay. Now, first of all, Mr. Roe, with reference to making that type of study, isn't the thing that a reservoir engineer wants to see is how many reservoir barrels are being taken out per psi drop?

A No, that's not right. My objective would be -- I'm going to get the gas anyway. I don't care how fast it comes.

My objective is to maximize the number of stock tank barrels of oil I would recover from the reservoir given that my amount of gas in the reservoir is constant, fixed, and once it's gone, if I don't get the oil with the gas, I'll never get the oil.

Q Well, are you saying that determining

how many reservoir barrels are produced per psi is not something that a reservoir engineer should look at to see how efficient the reservoir is?

A Mr. Douglass, there are occasions that I would think that's proper but my objective is oil recovery with the idea that gas recovery is probably going to happen no matter what we do.

Q Well, if -- if you produce a barrel of oil with one (unclear) one psi drop in the reservoir, if you produce a barrel of oil with one psi the drop in the reservoir, if you produce that at the surface, and you produce a barrel at the surface and you have 2 psi drop in the reservoir, then you say the top one is more efficient than the bottom one, as I understand it, is that correct?

A I'm saying if you had -- yes, given 100 pounds you're going to recover 100 barrels in the top one and 50 barrels in the bottom one.

Q All right. Did you look at Mr. Hueni's Exhibit -- let's see which one it was -- Twenty-two? Did you have a chance to look at that?

Did you examine that?

A Yes, I remember that. I was here when Mr. Hueni presented it.

Q It shows the February to June '87 period and shows what the voidage is as far as that period of time is concerned in reservoir barrels to get a barrel of oil at the surface.

A Yes, sir.

Q Did you disagree with that calculation?

A I did not check it but I understand what Mr. Hueni is saying.

Q And it shows that he got 30 -- it took 3176 stock tank barrels per psi during that period of time to get the oil production up, is that correct?

A I --

Q That was the difference in --

A I agree that's that what Mr. Hueni's got. I haven't gone through Mr. Hueni's calculations.

Q And in what you call the high rate and what we call the normal rate, then it would be 3662 stock tank barrels per psi drop in pressure, (not clearly understood.)

A Yes, it would. Basically that's just a restatement that at the higher oil rates you have a lower gas/oil ratio.

Q All right, and -- and you would agree that's more efficient as far as the reservoir is concerned.

A If all wells within the reservoir will be treated in that manner, yes.

Q Well, this is. You understand that this is not only the wells in Gavilan but this is in the expansion area that showed this.

A Well, that is why I think we may have a problem, is the wells in the expansion area are treated differently than the wells in the -- first off, the reservoir voidage that occurs from any well in the unit is much less than the reservoir voidage that a well of any quality in Gavilan for the simple reason that I don't believe the barrier exists, so when Mr. Greer reinjects the gas, rather than sells the gas, and that's the big difference between looking at reservoir voidage, is the reservoir voidage from the unit is -- is much, much less, and I don't have a number to give you, but any gas produced out of Gavilan is either vented or sold. Any gas produced out of this unit is reinjected.

Q And in the restricted rate period the number of barrels, stock tank barrels per pressure drop went back to what it was before, didn't it?

A That calculation would support that, yes.

Q You haven't made that calculation in Gavilan, have you?

A Well, again, I'm aware that there are some wells in Gavilan that are actually approaching the category of gas well based on the last C-116 test; it wouldn't surprise me if the Commission thinks they need to be classified as gas wells.

Q Is the answer to my question, yes, that you have not made that calculation in Gavilan?

A Not for this hearing, no, sir.

Q And you haven't made a calculation of the overall pressure in the period that you're talking about here as far as Gavilan is concerned, have you?

A Of the overall pressure in --

Q That's right --

A -- the unit?

Q -- the pressure in the reservoir.

A Yes, sir, I have. It's reflected on that tabulation.

Q Are you saying this is the pressure in the reservoir or is this just the pressure in those wells?

A I, because of what I see on that tabulation, plus the pressure data that was included in the 27 wells in my Exhibit Number Ten, I feel very, very certain that that is a good measure of pressure throughout the reservoir because any time we can take wells like the Dr. Daddy-O, the Homestead Ranch No. 2, or the Loddy No. 1, and measure with those wells not producing, what's happening in a reservoir, I feel reasonably certain when we shut those same wells in, they are going to respond to reservoir pressures, yes.

Q You think you have determined the average reservoir pressure from this.

A Yes, sir, I sure do.

Q Okay. Did you determine the gas/oil ratio during the -- what you call the high rate and the restricted rate of production (not clearly understood)?

A Yes.

Q And that would be just in the Gavilan. Or would it be the Gavilan plus the expansion area wells?

A The production numbers here?

Q Yes.

A That would be just Gavilan.

Q Oh, is this just Gavilan production here?

A Yes, sir, it is.

Q But you've used the pressure drops in the unit wells, also?

A Well, if you'll look, the pressure in the unit wells is very similar to the pressure in the Gavilan area wells; but you are right, I have unit well pressures included in this tabulation, but I would have to look, I really don't think that they could change the average, for instance, that is the reason I put a second average there that would exclude high and low pressure to see if it was sensitive to a number being way out of range, and for instance, you can see the same period it's changed 23 pounds considering all wells and 23 pounds considering (not clearly understood).

Q Just so I'm clear, the pressure drops you've shown here versus production is -- does not include the production from the -- all the wells that you list here for the pressure drop.

A Mr. Douglass, all of my numbers did not include anything, any production from West Puerto Chiquito.

Q But the production from West Puerto Chiquito as far as, you say, in the expansion area, did affect these pressures, didn't it?

A No, I don't think I said that.

Q Well, I thought you said this was all one reservoir and to produce these wells that they would affect across that boundary line.

A Yes, and I also said that the reason that there's been a substantial amount of development along both sides is so that the flow across the boundary would be very low and it's my feeling that the pressure that we have presented on this tabulation, which is mainly why I included the wells in the expansion area, so we could see that relationship, and if we could look, for instance, let me find a well -- say the bottom two wells in the February

13th -- February 23rd pressure survey, they're within 4 pounds of each other and they're around 950 pounds.

If we look at another well that's along the boundary within the Gavilan side, it could be the Hill No. 1 operated by Meridian, it's 957 pounds, certainly within the very low range of Gavilan -- or of West Puerto Chiquito, or similar range, and so the pressures right in this area are very similar to each other. Now I -- I thought I testified, and it looks like I picked the one pressure that is a little higher in the Gavilan than the West Puerto Chiquito wells by just a very small, 1 pound in one case and 5 pounds in another, but I think the pressures in those areas are very similar and if there is a gradient, it's from West Puerto Chiquito to Gavilan.

Q Mr. Roe, the gas/oil ratio during the time of what you call high rate production, or the initial test period, was about 36 percent lower than it was during the restricted rate or the second test period, is that correct?

A Yes, sir, in fact during the high rate of production; it averaged 4926 and during the low rate of production averaged 6611.

Q The -- did you testify that at the high rate of production it would be 16 more months of production left?

A What I said was given the fact that our reservoir pressure is averaging about 880 pounds and we're completing it at 45 pounds a month, I think that's about 16 months worth of pressure, yes, sir.

Q The -- on your Exhibit Three you show the -- that it produced 2183.4 MCF in 4-1/2 months, is that right?

A 2183 MMCF?

Q Yes.

A Yes, sir.

Q In 4-1/2 months, is that right?

A Yes, sir.

Q And how much would that be per month, then?

A About 485-million a month.

Q 485 MMCF per month, and if it produces another 16 months how much gas would that be?

A It would be 7.7 or 7.8-million cubic feet.

Q 7.7-million, that's close enough for government work.

And at the -- you can also determine how much it produced each month if it produced three months at the low rate of 948.2, is that right? How much would that be each month?

A That would be 313-million a month.

Q 313, and I believe you said 7 or 8 year, 8 years might be too long, why don't we use 7?

A No, I -- I -- if that's what it came out, I said that's what you get when you divide the pressure by 8 pounds a month, but I meant to say, if I didn't, that I didn't feel that probably was realistic and --

Q How many years?

A I have not made that calculation. With time the gas production will increase. In fact, we see that right now the gas voidage is increasing, so given the fact that the gas reserves are constant, unless the gas cap starts showing up in Gavilan, the gas volume will increase.

Q Well, if you use the same test that you've been -- that you show in Exhibit Three here, that is psi drop, you said it would be 7 or 8 years. If you just use 7 years, that would be 84 months, wouldn't it?

A Yeah, but I think I said that that wasn't probably realistic. I wouldn't use that to calculate gas reserves.

Q Well, somebody might not use the pressure, either, to determine how efficient a reservoir is, would they?

A I would hope most reservoir people would.

Q If it were 84 months, approximately how much would that be at the low rate gas production?

A If you were able to produce it for 84 months at that rate it would be 26-billion cubic feet.

Q 26.

A Yes, sir.

Q About 3 or 3-1/2 times greater than at the high rate.

A Yeah, but that -- that won't happen. Like I say, I hope you weren't thinking I think that because I don't think that.

Q Well, don't you think that might be the impression that's left with this Commission, if they're going to just use psi per stock tank barrel of oil at the surface to see what the efficiency is?

A No, in fact that's why I qualified that I didn't think it was realistic to plan on an 8-pound per month pressure drop under continued low rates of production. production.

Q Looking at the chart that's on the board here to -- that's Exhibit Four, I believe, do I understand that the -- first of all, that the production you show here is only Gavilan production?

A That is correct and when I gave that I qualified that the Canada Ojitos Unit wells were on there only to develop a relationship to what's happening in Gavilan.

Q All right. Do I see that the original pressure in the Hawk was about 1765 pounds?

A I will not say that's original; that's the first pressure we had in the Hawk Federal No. 2.

Q The first pressure you had? Well, that's the initial pressure you measured and that was after about 200,000 barrels of production from Gavilan?

A Yes, sir.

Q All right. Do I -- did I understand you to say that it was about in January of '86 that you see the change in slope of this pressure decline? You've got a red line drawn out, a joint, I guess maybe a joint here a little later in March, January, February -- January, February, March?

A It doesn't miss January much but it's actually probably a little closer to -- to February, or March.

Q Well, doesn't that indicate to you that the expansion area wells that came in January of '86 started affecting this pressure decline?

A I think that it's possible. I also think that because prior to that time, though, 11,000 barrels of oil per psi, I think that occurred during a time when there was only, well, the maximum of 34 wells in the Gavilan, none in the expansion area, and none to the north, and I personally feel that we were actually experiencing a little pressure maintenance effect in the Gavilan Mancos Pool at that time, and had we not had communication with the West Puerto Chiquito Pool, we wouldn't have had the rate of pressure decline of only 5 pounds a month.

Q When you say pressure maintenance, what you're really -- that's a euphemism perhaps in this period for being drainage from the expansion area (unclear), would that be right? That we had drainage from the expansion area into Gavilan so that would be what you call pressure maintenance?

A I hate using the word drainage. I think we had some migration from West Puerto Chiquito into Gavilan, possibly.

Q And from that date on the pressure curve took a substantial change and that was the time when the expansion area wells came on.

A No, there were other events happening. In fact, when that -- that curve changed there was only four wells in the expansion area and in the whole expansion -- two rows of the expansion area.

I think one of the biggest changes that happened is we went from 34 wells operating January 1st of

'86 to at the time that curve took its change there were 37 wells in May of '86, five months later, and in September, '86 there was 41 wells. That was a time that everybody was getting into the act out there.

Q If you included the production from the expansion area represented by the pressure from the expansion area, it would flatten out this curve, wouldn't it?

A Yes, sir, it sure would.

Q Do also --

A Let me qualify that. If I do that, I also want to take in -- from my perspective I need to take into account the gas injection and I do need to consider reservoir voidage at that point and I had hoped to stay away from that.

Q Let me ask you with reference to -- I believe your counsel asked you if the gas/oil ratio didn't appear to jump up here, I believe it was in September, and that's when the Commission put in the restricted rate.

A September was the first month, yes, sir.

Q All right. The -- do all these wells build up at the same rate in the Gavilan?

A No, sir, they do not.

Q So if you have pressures down here, then an explanation for those pressures being lower than other pressures in the Gavilan is that they hadn't built up to the same point?

A Yes, that's possible, but one of the wells in that group is the well we have a real documentation of reservoir pressure performance with time and we know that it's fairly well connected with the reservoir so it's my feeling that the pressure in that well would reflect the pressure in that part of the well. The Loddy is not a poor well. We've put in some of the wells that would be slow to build up, or wells that are in that category. Mobil's best well is down there, and so I feel it's going to build up as fast as any of the wells, including the Loddy and the High Adventure No. 1.

Q I believe it was about in this point in your testimony where you testified about pressure, how you determined an 11 pound pressure drop -- excuse me, 11 pound pressure drop per year that -- that that didn't come from a pressure in November of '87, that came from an observation well pressure that you had?

A Well, as you pointed out yesterday, my testimony 11 pounds was prior to taking the November, '87 pressure.

Q Well, I understand. I was just trying to do that to orient what you told me.

Did you say that you calculated 11 pounds per year by using an observation well pressure?

A Yes, sir. I had pressures well in the unit, yes.
Q Was that the -- was that observation well the A-23?
A No, sir.
Q Which well was it?
A It was the unit well -- it was one of the gas injection wells. I'd be happy to give you that but I don't have it at my fingertips.
Q You don't recall which well it was? It wasn't A-23?
A A-23, no, sir, I know that.
Q I think it's nearer K-13. Was it K-13?
A It could have been, yes.
Q You don't recall. Let me ask you, with reference to that, you said you'd worked closely with Mr. Greer.
For some period of time in the unit over-injection has been occurring with reference to that operation, is that correct?
A There -- yes, sir.
Q And during that period of time the pressure had been going down, hadn't it, in the unit?
A During the period of over-injection?
Q Yes.

A I don't know that.

Q Well, I thought that that's how -- at least you calculated an 11 pound pressure drop in 1980.

A Yes, I did that --

Q Per year?

A Well, all that I knew when I made that calculation was the pressure in 1972 or so and the pressure in 1980, and during that period of time it averaged that, and I do recognize -- it may not be fair to imply, but we had some other -- other reasons to believe that that was reasonable, though, or I wouldn't have used it.

Q Well, are you saying that you and Mr. Greer weren't concerned during the period of over-injection that you still weren't able to keep up with the pressure drop?

A Well, first of all, Mr. Douglass, when that was happening I knew nothing about the West Puerto Chiquito Pool, and that may be a question you ought to ask Mr. Greer.

Q The -- if the pressure in -- do you recall what the pressure was in 1980 in the observation well?

A Again, I'd be happy to provide that. I don't have it with me.

Q It certainly was not at the level that

Mr. Lee said it -- that Mr. Lee's computer model says it was in November of '80, up around or in excess of -- looks to me like it's around 2000 pounds.

A I would have to agree that sounds a little high to me, but I haven't had a chance to review Mr. Lee's data to the extent that I could really say. Yes, it does seem a little high.

Q A little high, about 5-or-600 pounds?

A I would like to review the data before I made that statement.

Q Well, if the observation pressure was 1350 pounds and Mr. Lee says that the pressure in the unit is 1900 pounds, that's -- that's not just a little, is it?

A No, that would fall under the range you just mentioned.

Q As Mr. Weiss said, maybe that would be lots.

A It would be lots, but not enough to keep flow across your barrier.

Q You're just like Mr. Kellahin, John. You don't think I'm going to rise to the bait.

Are you saying that the conditions exist on Exhibit Twenty, as shown on Exhibit Twenty, that there is no barrier between West Puerto Chiquito pressure maintenance area and the expansion area and Gavilan?

A I say that I can understand how you could have that pressure profile. I might question whether you've actually got the right pressure profile for Gavilan.

Q Well, I'm asking -- my question is, if on Exhibit Twenty, if that pressure profile is correct on Exhibit Twenty, doesn't there have to be a barrier between the expansion area and Gavilan and the pressure maintenance area?

A No, sir, there does not.

Q All right, what is your explanation of how you could have a pressure profile as shown on Exhibit Twenty and have communication across the barrier?

A I think all of the maps I've ever seen Mr. Greer present show that there's -- and I don't remember if he's used the word "barrier" -- but there's always a cross-hatched area with some question marks in it long before Gavilan ever -- ever existed, and so I think in my mind and in Mr.Greer's mind, and in everybody's mind, I think there's no question there is a reduced Kh part of the reservoir, a reservoir that is not as high in transmissibility between the gas injection area of West Puerto Chiquito and Gavilan. We see that in the tightness of the gas injection wells. We know the gas injection wells are communicated with wells within the gas cap by monitoring changes in pressures with respect to different injection rates or whether we're selling gas or not.

I say the same kind of a transition exists between the initial pressure maintenance area and the expansion area. It is a reduced permeability and as long as there's a pressure difference across that point in the reservoir it will account for a higher pressure on one side of it and a lower pressure on the other side of it, and I think that was described as pressure loss, pressure loss across the -- and you might think of it as a damaged zone or something of that sort, but this reservoir has never been in static conditions since the Canada Ojitos Unit began producing, and as long as that's the case, any permeability reduction will result in a pressure drop, a higher pressure on the high side and a lower pressure on the low side.

Q You haven't had any significant drop in the pressure maintenance area since the Gavilan production came on, have you?

A I think that there hasn't been a significant drop, no.

Q Essentially there hasn't been any; still around 1400 pounds, isn't it?

A I don't know that for sure. I haven't checked it.

Q And your explanation for this pressure profile on Exhibit Twenty, if it's correct, is that there is an area there of some retardation but it's not effective to keep the flow from moving across.

A It's not effective as a barrier. Yes, that's my feeling.

Q All right. What other core did you look at besides the 3-15?

A As a working interest owner in Bear Canyon Unit I personally observed the complete core from the Bear Canyon Unit No. 1, which cored all of the A, all of the B, all of the B, and a good part of the C zone.

Q Is it what you call a C zone producer?

A It was initially. Since Amoco has recompleted the well in the A and B, it's a little early to tell, but I think early indications, it's only been on production a week or two, but I think we could say we've picked up additional production in the A and B.

Q Does it appear to be very much addition?

A Like I say, it's a little hard to tell right now, but yes, I would say that there's no question that we've got more oil and maybe even a little more gas.

Q On your Exhibit Five, do I understand that you could actually determine the amount of acreage that is -- I don't know what's the term used in New Mexico, whether it's dedicated or proration unit or you say spacing unit, you've determined the spacing unit for the -- for the wells there, isn't that correct?

A That was the intention of that column, yes, sir.

Q Were you aware that there's 35 -- excuse me, 36,075 acres if you add up the spacing units that you show here for a producing well?

A I haven't done that so I can't say that checks, but that was in the ballpark --

Q Well, subject to check.

A Subject to check that's in the area where we -- we feel the acreage within Gavilan, yes, sir.

Q And can I tell from your Exhibit One what March production was for the field, as you call it, Gavilan, that 44,170?

A It's March, 1988?

Q Yes, March, 1988.

A Yes, that is correct.

Q And that would be at the restricted rate of production, is that right?

A Yes, sir.

Q How much would that be per acre?

A I'm going to leave my calculator at home next time.

Q The Commission may want you to do that, too.

A What was your acreage figure?

Q 36,075.

A That would figure out to be 1.2 barrels of oil per day per acre.

Q 44,170?

A I'm sorry, barrels per month per acre.

Q 36,075, if that's correct off of your exhibit, would be how much?

A 1.22 barrels of oil per month per acre.

Q Barrels of oil per month per acre. Now, are you aware of the spacing units that have been assigned to the producing wells, the 9 producing wells in the expansion area? Maybe 10 now in March, I'm not sure.

A Well, they're all on 640 acre spacing but I think there may be some sections that have got 2 wells.

Q So if they want two wells on a section, they would have 320 for each well?

A That's the way I believe it would be handled.

Q Would you accept, subject to check, on the 9 wells that we see as producing, that they have 5120 acres for their spacing unit, and would you also accept, and I think we can get the production -- my folks tell me they actually got the production numbers out of your Exhibit Two, and those --

A Mr. Douglass.

Q Yes.

A I'm not sure, there's at least 12 sections in there and I think the acreage may actually be just a little more than that.

Q All right, give me whatever you want.

A I - I would use no less than 7680 acres.

Q 7680.

A But I think we're actually dealing with a little more than that.

Q Well, 12 times -- you want to make it bigger? Tell me how much acreage you want per well. Is that 12 wells? How many wells in there?

A Well, just a minute and I'll check.

There's roughly 14 wells, I think, and I get that knowing the last well drilled was No. 38 and I think it started with Well No. 24.

Q Do you know how many producing wells you've got in the expansion area?

A No, short of counting them, I don't.

Q Do you want to use 14?

A I don't know, you're asking the questions.

Q Well, I want to know how many acres are assigned to producing wells in the expansion area. 640 would be the maximum, is that correct?

A Yes.

Q 14 wells, is that what you think the number is?

A Well, can we tell him, Mr. Kellahin? It appears to me that we have the exact number.

Q Our witness already testified it's 9. I want you to tell me how many producing wells there are. If it's different, we need to get the right information in the record. I'm not sure his figures are for march, but you tell me what you got for March.

A There is actually 15 wells that are completed in the two rows of sections that we identify as the expansion area.

Q All of them got 640 or is it some 320?

A Well, I, for what I think you're trying to do, I think it's more reasonable to think that we've got two rows of sections that are 10 sections long, so what I would prefer to use is 640 acres times 2 times 10.

Q You're going to get up to 20 now.

A Well, yes, I am.

Q You have 15 wells and now you want to use 20.

A No, I'm talking about sections of land. I -- I personally feel that, especially in the unit, that one well will drain more than 640 acres.

Q Well, if you're going to determine how much is being produced according to the spacing unit, shouldn't you use the spacing unit?

A Okay, if you like, yes.

Q You've got 15 out there, you say you've got 15 producing wells.

A Yes, sir.

Q All right, and 640 a well, how much -- how much acreage is that?

A Well, for your calculation let's use 640 acres, but there are some sections that have 2 wells.

Q I'm not going to quibble about that. Give me 16 times 650. I'll let you have 640 for every one, or the Commission will.

A Okay, that's 9600 acres.

Q 9600 acres. And would you accept subject to check that the expansion area produced 51,000 barrels 420 in March? That sound about right to you?

A Certainly, yes.

Q You do know that the expansion area produced more in March than Gavilan, don't you?

A Yes, but that's what this hearing is all about. With the lower gas/oil ratios that exist and the voidage that is being created, that -- that should happen.

Q You better believe that's what this hearing is about.

What's 9600 into 51,420?

A 5.35.

Q 5.35, so in March under the restricted allowable rules, acreage assigned to 15 producing wells received production of 5.35 barrels whereas the Gavilan Field wells got 1.22 barrels per acre.

A Well, Mr. Douglass, this is one application where we really do need to deal with reservoir voidage and in that tabulation we would have to take into account that the net reservoir voidage within the unit is not at all comparable to the net reservoir voidage in Gavilan, mainly because all of the produced gas less whatever (unclear) to return to the reservoir.

Q If you assume that the barrier does not exist --

A Which I do.

Q If you assume that the barrier does exist, then the expansion area is producing 5.35 barrels of oil per month per acre, versus 1.22 for the Gavilan.

A Which is one of the real benefits of being unitized.

Q No, I think that isn't really. That's one of the benefits of having restricted rates.

A Well, yes.

MR. DOUGLASS: Pass the witness.

MR. LEMAY: Mr. Lopez, do you have any questions?

MR. LOPEZ: No, Mr. Chairman.

MR. LEMAY: Mr. Lund?

MR. LUND: Just one question.

CROSS EXAMINATION

BY MR. LUND:

Q Mr. Roe, on your Exhibit Two, the blue folder, I was looking at the back for the production information on the Canada Ojitos No. 22 Well, and I didn't see it. Am I just missing it some place?

A Let me check real quick, Mr. Lund. I think that's -- that would be the low rate Mancos well that shows up in the barrier on Mr. Mallon's map that is actually completed in the Dakota formation.

The long term plans tendered by Mr. Greer are to complete that in the Mancos but as of yet it has only been completed in the Dakota, and tested, and I'm not sure what his plans are to complete it in the Mancos, but it has not been completed in the Mancos even though it is represented as a Mancos completion on at least this map.

Q And the production information is not contained in your exhibit?

A Well, Mr. Lund, it hasn't been completed in the Mancos yet. It's only been perforated in the Dakota and because of that I think probably the well has been shut in since testing. I do know that Mr. Greer has given some thought, and has actually circulated to the working interest owners a proposal to equalize the Dakota and Mancos right, so that the Dakota possibly would serve as a source of gas for pressure maintenance, but there is no production from the Mancos from Canada Ojitos Unit No. 22 yet. It has just not been completed in the Mancos.

Q And your testimony was that it's very small production from the Dakota, is that what you said?

A I don't remember quoting a number but that is correct. That Dakota is not very well in that well and the number I remember is about 120 MCF a day and about 1 barrel of oil a day.

Q And the Dakota production from that well is not in here.

A No. I'm not sure where the Commission carries that. It's probably going to be an undesignated or Basin Dakota Pool. It won't be in the Gavilan Mancos Pool.

It's probably -- I don't know, I think Basin Dakota Pool, so that's probably where it is.

Q All right. I just wanted to confirm it wasn't in this (unclear.)

A That is correct. Any production would not be from the Mancos.

Q Thank you.

MR. LEMAY: Additional questions of the witness?

Mr. Chavez.

QUESTIONS BY MR. CHAVEZ:

Q John, your exhibit on the West Puerto Chiquito Mancos production statistics, is there a well missing operated by Amoco, the Schmitz Anticline Well, in Section 25 of Township 24 North, 1 East?

A Yes. In fact I'm afraid I didn't realize until -- we didn't pick up the Schmitz Anticline or the recent State Com CC or the Wishing Well, and so there are three additional wells in the -- that general area, although I guess the Wishing Well and State Com CC aren't additional, or, you know, they're in the pool, so there are three wells that are not included here. It was an unintentional error. I just got wrapped up in West Puerto Chiquito and Gavilan and forgot about the Schmitz

Anticline.

Q In your study of the bottom hole pressures in the Gavilan Pool, did you find that the discovery pool pressures were lower than they should have been in the pool?

A Yes. We felt that the initial pressure that we observed in the Gavilan 1 were approximately 100 pounds or so below what we would have anticipated virgin pressure to have been.

Q What did you attribute that to?

A Well, at the original pool hearing Mr. Greer testified that he felt that was evidence of -- of depletion in West Puerto Chiquito and migration from Gavilan to West Puerto Chiquito.

I feel that that's probably as good an explanation as any. The development to the west in the West Lindrith was very fair removed at the time Gavilan was developed, so it's my feeling that we probably had some migration into West Puerto Chiquito prior to the discovery well, and that has been placed in the records.

Q On the first straight line you drew on your graph on Exhibit Number Four at the top, does it appear to you that the wells that are producing both within Gavilan and in the proposed expansion area are functioning on the same type of pressure drop, same rate of pressure drop, with the production of oil?

A Pretty much the top line I would say so, yes, sir. Now, that's what I -- that's how I explained the difference for the deviation of curves at the latter part of the curve with the proximity of those wells to Gavilan and the unit providing a pressure input.

But yes, up early in the curve the reservoir pressure in that area was very similar.

Q Is there some point on that curve that you could estimate that what you term as pressure support from the pressure maintenance project is visible and the lines divide that give you your -- the two lines you end up with?

A It really became apparent to me that there was something happening when I put the three pressure measurements on that were a result of the Commission ordered test.

The last pressure that we have prior to that, there's kind of a group of wells that would be, oh, just past the December '86. We were noticing a change in trend of some of those wells at that time, although I -- we had that prepared for an exhibit pretty much through the green line at one time. We just added the July, November, and February pressure points to it, and that's when we first really figured out that something had happened.

So what I'm telling you, we really don't have an explanation.

Q On your Exhibit Number six --

A Yes, sir.

Q -- you only used wells producing within the Gavilan Pool proper. Did you make any estimations on the change in total share of production including the proposed expansion area wells?

A No, Mr. Chavez, we were -- again my primary concern is with Gavilan and how the reserves will be distributed in Gavilan, and you'll -- you'll note that we left Amoco Production out of these calculations primarily because Amoco really had no -- or very little production during the high rate test, so what we were trying to do here is reflect how the reserves would be distributed within Gavilan, not necessarily the total pool.

Q Considering the issue of correlative rights which I think you're trying to address with this graph, might not we consider the problem of correlative rights across what we consider the pool boundary?

A Well, I -- all of my conversations with Mr. Greer on that are that he is willing to try to develop a method of some sort so that we have similar pressures on both sides of the boundary and we don't have a cross flow, but that is about the only method to deal with correlative rights, is try to stop the flow of unitized fluids into Gavilan or Gavilan into the unitized areas.

And it would be something that we would propose to take care of with -- with some other method. In other words, the fact that gas is reinjected into the unit, you'd have a different reservoir voidage on the unit side than you do in Gavilan, so you don't have a similar situation in Gavilan that you do in West Puerto Chiquito.

I maybe didn't understand your question.

Q That's close enough. On your Exhibits Seven, Eight and Nine, were there any changes that you noticed within the proposed expansion area that might could have been noted on these maps that weren't?

A Mr. Chavez, I -- given more time I wanted to look at the expansion area myself but I did not look at the expansion area.

I do know that the gas/oil ratio was not as near a problem in the expansion area as it is in Gavilan, so they won't be the same, but I'm sure there would be some differences.

Q You have stated a few times now that all the gas produced within the pressure maintenance project has been injected. Are you aware of any gas at all being sold to El Paso Natural Gas from the unit within the last year, two years?

A Yes, only during the high -- beginning during the time that we were -- the initial phase of the production test, the unit did sell gas for two reasons. One, it is necessary to make some adjustments to keep the pressure in West Puerto Chiquito a little more balanced with the Gavilan and you can't do that by reinjecting all of the gas, plus at the higher -- higher rates there was quite a bit more gas from -- than we could reinject.

MR. CHAVEZ: Thank you, Mr. Chairman.

MR. LEMAY: Additional questions?

RECROSS EXAMINATION

BY MR. DOUGLASS:

Q Mr. Roe, with reference to the wells in the expansion area, are you aware of what their deliverability is as far as oil and gas is concerned?

A No, sir, I don't know the individual wells, but the statistics are presented in my Exhibit Number Two.

Q But you don't -- you don't have the -- you don't know or have available to you, as far as you can tell within a reasonable time, what the deliverability is of the wells in the expansion area. It's the figures you don't remember.

A That is correct.

Q Do you remember what the deliverability is of the Dugan wells in the Gavilan Field?

A Well, Dugan operates one well in the Gavilan Field and so, yes, I do.

Q What is it?

A One barrel a day and about 35 MCF a day. Now, Dugan does have interest in about 26 other wells in the Gavilan.

Q 26 others. Who operates those?

A Various operators, not just one.

MR. DOUGLASS: That's all I have.

MR. LEMAY: Commissioner Brostuen.

QUESTIONS BY MR. BROSTUEN:

Q Mr. Roe, on your Exhibit Number Four, that's the ones you have on the board before you there, are all the pressures that are shown on this exhibit observed pressures or are they some that are taken from the rainbow map or by some other method that's devised by Mr. Greer for pressure determination?

A All of the pressures here that are on

this map, plus I mentioned that I had so many more that if I put on here, it would just confuse the map. It wouldn't add to the story or actual measurements.

On occasion I might have measured a fluid level to determine pressure, but generally these are all on measurements.

Q You discussed the 72-hour shut-in period briefly and it appeared from the exhibits that have been presented thus far that pressures were continuing to climb, that they're not stabilized in a 72-hour period, you said, but anyway, you were taking these pressures field-wide so that essentially it's comparing apples and apples, not apples and oranges.

However, what would you anticipate what would have been the change in any of your determinations regarding pressure, pounds per square inch per barrel of oil and so on and so forth, had these pressures continued to be measured and the wells shut-in until the wells had stabilized?

A Well, barring the major continued build in the pressure, and it is my feeling that if they weren't stabilized, in other words the build-ups that we did have, were -- were increasing at different periods so that a lot of the wells actually built-up. The Fisher Federal in the last test built up completely in 9 hours.

There were wells that still had some build-up ranging anywhere from 2 to 4 pounds a day, I think.

We did not have build-ups in all wells, though, and so generally we're trying to compare even the wells we did have build-up, or at least the pressures I'm using is the 72-hour pressure, so that it will be comparable with the 72-hour pressure from the previous test and also the 72-hour pressures of the other wells in the field.

Q I see. You also discussed briefly some of the wells that would -- that are located along what the Proponents have referred to as the barrier. The F-20 Well, Well, COU No. 22 I believe is the one you said was completed in the Dakota, production rate of 1 barrel of oil a day, and I forget how much gas. Was it a completion attempted in the Mancos?

A Not yet. It's my understanding Mr. Greer plans to do that.

Q But there's been no attempt at perforations or anything that you're aware of?

A That is correct. The Dakota is the only zone that has been tested, as far as I know.

Q The -- the well just to the south of that, the Benson-Montin-Greer G-32, (not understood) that was submitted, Exhibit Number Five, submitted in -- earlier this year, in the hearing early this year, they show the -- this well as having produced 7 -- now this is a figure that was presented by Mr. Greg Hueni, I believe, 6000 barrels of oil cumulative and the well was shut-in.

Do you know the status of that well and whether or not that well is essentially depleting and what reservoir is around it?

A This is probably something that Mr. Greer could better answer. It's my understanding they had a jelled oil stimulation and that he thinks there may be some problems with that system, but beyond that, I -- I don't know.

Q Well, perhaps I should defer these questions to Mr. Greer, then.

A Yes, sir.

Q Okay, thank you.

A You'll get a better answer.

Q Thank you.

MR. BROSTUEN: That's all I have.

MR. LEMAY: Commissioner Humphries.

QUESTIONS BY MR. HUMPHRIES:

Q Why wouldn't the huge withdrawal of Gavilan Mancos have made some kind of measurable response in pressures on the decline curve, or the long stable pressure curve in the pressure maintenance project, or the entire West Puerto Chiquito, given that relatively dramatic amount of new wells and large production and the relatively dramatic drop, if there's no restriction between the two?

A First off, I think to accept that the pressure performance in the original area of the pressure maintenance is truly represented by that long line covering 20 years where we have basically a point on each end, even though that may approximate the pressure, we don't really know that for sure and I am not positive whether or not we've seen a pressure change in that original pressure maintenance area.

My thinking is that maybe we have, but Mr. Greer would probably be able to address that better than I would. I quite honestly have concentrated my efforts in the Gavilan portion of this pool and tried to keep knowledgeable in the West Puerto Chiquito, but as far as the bulk of the work goes, Mr. Greer has actually done most of that.

Q Well. assume that we're not even talking about 20 years. Let's say we're talking about approximately the same time as Gavilan Mancos came on, with the absence of the alleged barrier, even with over injection, wouldn't there have been some response expected?

A Yes, sir. I would expect that there probably has been a change in pressure but I just can't tell you how it's changed. I again have spent most of my time in an area that -- that Dugan is the operator and left West Puerto Chiquito up to Mr. Greer.

Q In the, well, in the discussion you have in Exhibit Six you talked about the large percentage of production of the Mallon wells, I think, yeah, the seven wells that produced -- or had the advantage of some 21 percent of the field production. Not respective of whose wells they are, isn't it possible that some wells would be better than others in that pool? I don't think anybody's suggested that the entire Gavilan Mancos Unit as it exists to date is totally homogeneous.

A Well --

Q I mean Pool, strike the word "Unit".

A Actually, presented on Exhibit Six is the difference between the two -- two test periods. During the high rate of production he actually from his wells produced 29-1/2 percent of the total pool production.

Q Well, my question is, though, regardless of whose wells they are, isn't it possible that some wells will be superstars and some wells will be duds?

A Sure, and that's just exactly what we have in Gavilan. There is a big contrast between wells. The problem I have is that we have an abundance of pressure information, a large part of which I included in my Exhibit Ten, which we did not devote the time to go through, because a lot of it was pretty redundant, but throughout the pool we see these wells are connected with each other so well that what happens in one well will affect another well shut in and so we have to, I feel, -- well, also my feeling is predicated on the fact that I think the reason we have a better well is because that particular spot in the reservoir is influenced by the natural fracturing of the Mancos more extensively than maybe a well that isn't so good, and so we're not actually looking at a difference in reservoir quality as being responsible, the reservoir -- I didn't say that right. The reservoir quality is better from the standpoint it's got more fractures, but it's the fractures that actually make the wells good wells or poor wells, as evidenced by the -- we talked a little bit about the Davis Federal 3-15. From all appearances and log measurements and even looking at the core, we saw fractures in the core. That should have been a much better well. It's offset by some of the -- well, Mallon's wells and they're some of the best wells in the pool. I don't think there should be any doubt about that.

The problem we have is that those wells are just left unchecked because they are better and because of the communication we have throughout the reservoir as documented with our pressure testing. It's conceivable that one well will drain much larger areas than that which is assigned to it.

Now, if it wasn't offset by wells that could also produce their reserves, then I would say I would not have quite the problem, but there is good wells in the the reservoir. They just aren't as good as Mr. Mallon's wells and so it's my feeling that if you let the good wells produce all they can there's going to be a big violation of correlative rights of the offset wells.

Q Well, one of the basic things I think the Commission's responsibility is to statutorily protect correlative rights, and I certainly didn't disagree with your definition that that was the amount of reserves and reservoir energy under one individual's land, or I guess one lease or multiple leases.

Is that -- the way I interpreted your testimony was that the Commission would need to accept that that was equally distributed across all of Gavilan Mancos Pool at this point.

A That's kind of the way I see what's happening there in the Mancos formation, is the actual storage capacity of the fractures is really very small. Porosity, when you consider a fracture as dividing the pool's pore space, to store oil in, and that's very likely why you can see such a big fight over is there secondary porosity or matrix porosity, is the amount of reserves that are in place are very small because some of us feel that it's primarily stored just in the fractures and they represent just a very small percent of the total bulk volume.

So I can't give you a number but, you, know, maybe one to two percent of the total bulk volume is all you have to store oil and gas in, if you subscribe to the fact that there is no matrix.

The areas that are more intensely fractured will have probably a little bit more oil in place than the part of the reservoir that isn't heavily fractured because of, you know, there are just more fractures, but it's not going to be in relationship to that well's productivity. In other words, you could have a good well because it's got good fractures, but it won't have an equal amount more of reserves in place than a well that's not quite as good.

Q One more question and then I'll be done here. Is it logical then to assume -- it strikes me as unusual that that much circumstance or chance would find it-self located in 7 wells out of 36,000 acres. Are you saying that the laws of chance or probability converged on those 7 wells?

A Well, you're talking to somebody who just drilled poorest well in the field, too, right in the middle out there. Yes, that's what happens.

Q It's just random luck?

A Well, I would like to think that it's more than random. We, we being Dugan Production jointly with BMG, conducted an areal photo survey of the area and a Landsat study.

We have that that guides us quite a bit as to where we locate our wells. We think maybe we can see on the surface what may project to depth in the Mancos. We have a lot of information put into the (unclear) but when you get right down to it, we thought we were going to get a good well with the Davis Federal 3-15 when we drilled it and we chose that well to take some core from as an Engineering Study Committee project.

I don't know that that discounts the value of the core, that it's in a poor part of the reservoir. I think probably what we see in the core is the matrix part of what the fractures are in. It would have been nice if the well would have been a little better so we could say, yes, this represents what we're producing from.

Q Thank you.

QUESTIONS BY MR. LEMAY:

Q Mr. Roe, on your Exhibit Number Four, the one behind the proposed area, when you start getting -- we're talking about shortly after January, 1986, when you start getting a change in the slope of the pressure curve, you also seem to be getting an increase of a GOR and if my memory serves me correctly, isn't that the approximate pressure of the bubble point in that reservoir?

A It's awful close. The two bubble point pressures that I have available, the sample that was taken in the Canada Ojitos Unit from Unit Well L-11 had a bubble point pressure of 1530 psia and the Loddy, which was a well operated by McHugh at the time, has a bubble point pressure of 1593 psia.

Q With my knowledge, and it's limited as to reservoir energy mechanics, the GOR will go up when the gas breaks out of solution, so you get at the bubble point increasing GOR's.

A Yes, sir.

Q But would you have a decrease in efficiency in the reservoir mechanism so that your pressure decline would be greater per barrel produced?

A Yes, you sure would. Part of, you know, I think we've all acknowledged that as the reservoir pressure depletes we are going to be producing more and more free gas and it's my feeling that with us getting a fractured reservoir that's so massive in thickness, in other words, we're dealing with something from top to bottom, whether it's all productive or not, that we've been perforating about a 400 - 450 foot interval. It gives us -- and then we turn around and stimulate that interval and it gives us lots of room for gravity segregation to occur at any point in the wellbore and so as we allow this gas to evolve from solution, which I don't care whose bubble point pressure you use, we're definitely below it now, you are going to be producing more free gas and if we don't make the best use of that gas, we will be wasting reservoir energy.

Q That's the other point, I don't know if we can get into it now, but I think the problem that I face, there are many of them, but the problem I see, and correct me if I'm wrong, that we have two contradictory points of efficiency.

One is that with the lower GOR's you've got a more efficient reservoir but during that period of high allowables the corollary of that was the exhibit showing that greater amounts of oil were produced per pounds of pressure drop and they just don't seem to fit in my mind. I can't visualize that. If you have a voidage that's -- that's less per barrel, your pressure drop should be less. They should go hand in hand, shouldn't they?

A Yes, but we have some other things that are cranked into this that -- in other words, if we were to do a material balance on the reservoir, that's really what we should do, but we don't know where the reservoir stops. I myself have very good reason to believe that the area to the north of Gavilan, primarily the Bear Canyon Unit, is communicated with Gavilan. So prior to that area coming on production, and it is just now doing that, I feel that area probably was migrating towards Gavilan, and that is a pressure inflow to the reservoir that we measure but we don't account for and it shows up in the efficiency.

We also, I feel, properly received pressure in the flow from the pressure maintenance project. We even, you know, have measured pressure depletion in Merrion's Krystina No. 1 in the southern part of the unit; a very poor well but still exhibiting a pressure decline inferring hydrocarbon flow from that point into Gavilan, and these are things that, you know, it's very difficult for me to account for that they will affect that, and -- because we do acknowledge that the in wells, some wells did exhibit a lower gas/oil ratio. I myself am a little suspicious that we're looking at something more of a mechanical thing in the reservoir because of the gravity segregation and once you get the oil moving it's better to keep it moving or it may be somewhat analogous to a low pressure or a gas reservoir with -- like a Dakota well in its later stages. Even though there's quite a bit of gas left you start having problems lifting the liquids from the well and it's very common practice to open those wells up, blow them to the atmosphere at a very high rate and get that fluid moving. Then once it's moving you can get it into the pipeline and hope the pressure doesn't go up and block you off.

And that may be somewhat analogous to what we're dealing with. We're dealing with a reservoir that's within 500 pounds of what I or Mr. Hueni have used as an abandonment pressure.

Q Well, given the performance of what we'll call the superstars now, the superstars, the Howard Federal, some of the Mallon wells, that seem to be the ones that react the most to the increased allowable, they're the ones that go from maybe zero to 10,000 barrels a month, and in Mr. Weiss' terminology, that's lots and lots of oil; 10 percent of the production from the pool; just a rough calculation, 100,000 a month, 10,000 from that well.

Is it possible that that well because of its spider web network can draw from further away and it can get some of that Bear Canyon oil with the higher allowable but it's not capable of doing that with a restricted allowable? Wide open does that draw from further away? Is that the way it works with some of these oil wells?

A Well, I -- I myself feel that that's the way must be working because wide open, you know, unless I'm grossly in error in how much oil per acre you have, it -- you -- some of these wells have cumulative production, including wells that when we were operating for Mr. McHugh, we produced way more oil in some of those wells than they could have had under their own 320-acre parcel of land, and so, yes, I think that's my biggest concern, that at the higher rate you are going to drain other areas.

Q We see in other reservoirs, this isn't unique, but it may be unique in the sense it can reach so far, if there is that kind of communication within the reservoir within the major fracture system. We're trying to visualize the performance of these super-wells.

A Well, I -- I'm not sure that all of the Bear Canyon Unit owners would agree with me, but it's my feeling that the initial pressure measured in the Bear Canyon 1 and, although we don't have a map right now, but the Bear Canyon 1 was probably 3 to 4 miles from the nearest Gavilan well that had any basic ability to produce, and it's my feeling that even that far away we were able to -- at that point in the reservoir had suffered some pressure depletion.

Q Thank you, Mr. Roe.

MR. LEMAY: Yes, Mr. Kellahin?

MR. KELLAHIN: Mr. Chairman, I have three quick areas of redirect.

REDIRECT EXAMINATION

BY MR. KELLAHIN:

Q When we look at the pressure measurements taken in the unit, Mr. Roe, in any of these periods of time, they are surface pressure measurements, are they not?

A For the unit wells?

Q Yes, sir.

A Yes.

Q I want to examine with you and see of there is an alternative engineering explanation that may account for the appearance of a differential on Proponents Exhibit Number Twenty.

Take, for example, what is the approximate range of depths of the wells in the unit itself?

A Okay. Now, Mr. Kellahin, you're talking about the wells that are in the original pressure maintenance area.

Q In the main project area, yes, sir.

A Because the wells in the expansion area, those were actual bomb measurements.

Q I see. I'm looking in the main project area. Are those wells in the range of 5000 to 7000 feet deep?

A They -- because of the dip in the reservoir they're much shallower and in order to extraplolate to the datum that we have here you quite often have to extrapolate the 700 to 800 feet and you're doing that below the depth of the wellbore and that will put you actually to a datum level that's below the base of the pay, and so what you're doing is you're having to guess where the gas/oil contact is and what the pressure gradient in the reservoir is from the deepest point you can measure down to the datum point, and so there is a very big uncertainty introduced if you don't know where your gas/oil contact is.

Q And that uncertainty regardless of the competency of the engineers making the calculation could induce a range of variations in the numbers to account for the difference?

A Yes. With the structural relief we have in -- from the gas cap area to our datum, the datum we chose was when we were studying Gavilan. We could well have chosen a different datum pressure had we been looking at the gas cap area, but we've got often the need to calculate the hydrostatic head of 800 to 1000 feet with no knowledge of what that gradient would be other than our best guess.

Now, again, that -- that applies only to the pressures that we have from the gas cap area.

Q Mr. Roe, I'm going to show you what I have marked for introduction as Dugan Exhibit Number Eleven. Taking the tabulation of information from your exhibits, Mr. Roe, and using Dr. Lee's display of what the tank has in each of the five tanks for the original oil in place --

A Yes, sir.

Q -- I want to use your information and determine for me, first of all, what we have for an original oil in place value within the West Puerto Chiquito Mancos Pool. If we use Dr. Lee's value for the tank on the far right, we have 21.3-million barrels?

A Yes.

Q And if we add that to the next two, the next tank, it's 29.8-million barrels?

A Yes, sir.

Q And then finally in the expansion area if we add in the 19-million barrels in that tank?

A Yes.

Q Do we get a total oil in place using that method of about 70.1-million barrels?

A Yes, we do.

Q Okay. When we go over to the Gavilan side and take the two tanks in that side of Gavilan, we have an original oil inplace value for the eastern portion of Gavilan of 17.1-million?

A Yes, sir.

Q And the western portion is 28.2-million?

A Yes.

Q All right. For comparisons, Mr. Roe, let's take a point in time beginning with January of 1986 for a 2-year period ending with January of 1988. Subject to check, Mr. Roe, would you follow through with me and if during that period of time the entire western -- the West Puerto Chiquito Mancos area within the unit has produced a total volume of oil of 1.6249-million barrels of oil. Do you see that in the summary?

A Yes, I do.

Q And if we look during that same period of time and find what the total production is out of the Gavilan area, it is 2.3425-million?

A Yes, that's correct.

Q Okay. To make the calculation to determine what the percentage of oil recovery in each area is to the original oil in place, am I correct in taking as the numerator for the unit side, including the expansion area, taking the 1.6249 figure and as the denominator the 70.1-million.

A Yes.

Q Do you have your little engineering calculator?

A Yes, I do.

Q Okay, what's the percentage of recovery in West Puerto Chiquito Mancos in that 2-year period?

A It would be 2.32 percent of oil in place.

Q And that's what's indicated in the lower right block when it says "COU"?

A Yes, sir.

Q And would you do the same thing in the Gavilan area and take the original oil in place as the denominator and the oil recovery as the numerator, and give us the percentage of recovery during that same period of time?

A That would be 5.7 -- 5.17 percent of the oil in place.

Q Take a moment and find that Exhibit 22, if you'll leave your calculator on, Mr. Roe, and if you'll take Mr. Hueni's reservoir voidage and just assume it's right, he's done it right, what does he show for reservoir voidage during the lower or restricted rate period in February '87 and June of '87, what is this number?

A Okay, during that period of time the reservoir was voided 8.35 reservoir barrels per stock tank barrel.

Q Multiply that by the stock tank barrels per psi pressure, and what do you get when you multiply those two together?

A We end up with 265,000 -- I'm sorry, 26,520 barrels of oil.

Q 26,520 reservoir barrels produced in this period per pound of loss of reservoir pressure, is that what that is?

A That's what I wound up with, yes, sir.

Q Do the same for the normal rate period, would you, please?

A That would be 35,595.

Q Rounding it off to 35,600 reservoir barrels per pound of pressure loss during the normal rate period from July of '87 to October, '87, that's what you got?

A Yes, sir.

Q Would you do it for the last (unclear)? What did you get?

A That would be 41,600 rounded off to the nearest hundred.

Q You get 41,600 reservoir barrels at the restricted rate per pound of loss of reservoir pressure.

A Yes, that's right.

Q Would you take the 41,600 and subtract the 35,600? What did you get?

A 6000.

Q You get 6000 more reservoir barrels per pound of pressure loss at the restricted rate than you do at the normal rate.

A Based on those numbers, yes I would say that that's what it indicates.

MR. KELLAHIN: Mr. Chairman, we move the introduction of Dugan Exhibit Number Eleven.

MR. LEMAY: Exhibit included without objection.

Additional questions?

MR. DOUGLASS: I have some.

RECROSS EXAMINATION

BY MR. DOUGLASS:

Q Mr. Roe, did you prepare Exhibit Eleven?

A Well, during the lunch hour I had prepared the numbers that went into Exhibit Eleven but I did not prepare Exhibit Eleven, no, sir.

Q Whose writing is this?

A I am going to anticipate that this is Sun's engineer with which I have worked very closely throughout this project.

Q Is the total production, let's see here, put this map back up, is the total -- is this to compare production from 1-86 through January of '88? Is that what it attests to?

A Yes, sir.

Q All right, and in the unit where the pressure maintenance is occurring, the total, do I see the total oil in place originally was 50 -- is that 51.1?

A You're talking about just the pressure maintenance area?

Q Yes.

A Yes, sir, that's correct.

Q And how much oil did it produce during that period of time?

A Just the pressure maintenance area?

Q Yes. 4 and 5.

A I guess

Q It's on your exhibit there, isn't it,

244.4, isn't it?

A Yes, sir.

Q Okay, how much is the oil -- if the oil in place is 51.1 barrel -- 50.1-million barrels of oil in place, how much did the unit, pressure maintenance unit present -- produce with this effective pressure maintenance project over there during that period of time of this oil in place?

A 0.5 percent, roughly.

Q 0.5 percent, so if the -- if this expansion area here, if my figures were correct awhile ago, it was pretty -- as I recall it was something around 8 percent or so. Is that correct, it was producing (unclear).

A Well, when we calculated how much was produced from the expansion area and assumed that it did not -- was not included by the unit, yes, sir.

Q If the -- if the barrier is there as we have indicated that it is, wouldn't producing a half of a percent of the original oil in place from the pressure maintenance area indicate that it's near the end of its producing life?

A If the barrier is there, yes, that's right.

MR. DOUGLASS: Pass the witness.

MR. LEMAY: Additional questions?

Mr. Chavez.

MR. CHAVEZ: Just one.

QUESTIONS BY MR. CHAVEZ

Q Mr. Roe, you interpreted the difference between the pressures on the ends of your lines there on your Exhibit Four as showing pressure support, is that correct?

A Yes, sir.

Q Are you assuming that pressure support is entirely from the pressure maintenance project?

A Well, no, not totally. One of the wells in that group of wells has probably been getting some inflow from maybe areas to the north, but with the exception of that one well maybe the rest of them would be from the (unclear). I really have just started to think along those lines of our communication with the area to the north and I do know Amoco does not agree with that, so I can't state, that, you know we are draining or communicating with the unit, but I -- if we aren't, then the only other place for that pressure support would be the pressure maintenance project.

Q Did you hear Mr. Bush's testimony about a bottom hole pressure approximately 900 and I forget what psi in the Bear Canyon Unit No. 1 to the north?

A Yes, sir. That -- that actually occurred after the well had produced approximately 12,000 barrels of oil. I do have the Bear Canon Unit wells plotted on that graph.

Q Thank you.

MR. LEMAY; Additional questions?

MR. DOUGLASS: Let me ask Mr. Roe just one question on the bottom hole pressure that we talked about.

RECROSS EXAMINATION

BY MR. DOUGLASS:

Q That you got some injection wells you couldn't measure the pressure down in the -- and -- and you had difficulty in measuring the pressure extrapolating it below the injection wells?

A Yes, sir.

Q Were you aware that the pressures that are shown on Exhibit Twenty out here, for instance, E-10, L-27, C-34, were those injection well pressures in the pressure maintenance unit?

A Yes, they are.

Q They are?

A Well, --

Q The E-10 is an injection well and the C-34 is an injection well and the L-27 is an injection well?

A Well, as I'm sure you're aware, those wells, the E-10, we arrived at that pressure by using surface pressure and calculate the bottom hole pressure, and the L-27, we did have a bomb measurement but we still had to extrapolate -- the bomb was, say, at a depth of about 6810, required us to extrapolate down about 300 feet to get to our subsea datum below the depth of the well.

The K-13 --

Q Wait a minute now, I'm sorry, I asked you about three wells. E-10, is that well in the gas cap? Is it an injection well?

A Oh, no, I didn't mean to (not clearly audible).

Q Were you aware that that's one of the three pressures at the end of this pressures on Exhibit Twenty?

A Well, yes, sir.

Q And the C-34, is that well an injection well or in the gas cap now?

A It's not an injection well.

Q Is it in the gas cap? I honestly can't tell you the location of the gas cap but I will say I don't know anything about that pressure.

Q How about the L-27? Is it an injection well?

A The L-27 is not an injection well but at the last survey we did have a gas gradient in the wellbore, which most of -- most of the wells in Gavilan did, and I think my only point is we have to extrapolate, like the L-27, we're measuring as deep as we can get with the bomb is 5850, and I think our +370 datum is 6730, so we -- we have roughly 900 feet that we have to guess at to get down to our datum.

MR. DOUGLASS: Pass the witness.

MR. LEMAY: Additional questions?

MR. KELLAHIN: Nothing further, Mr. Chairman. We pass the witness.

MR. LEMAY: Pardon?

MR. KELLAHIN: I have no further questions.

MR. LEMAY: The witness may be excused. Let's take a fifteen minute break.

(Thereupon a recess was taken.)

MR. LEMAY: Mr. Carr?

MR. CARR: May it please the Commission, at this time we call Albert R. Greer.

I request that the record reflect that Mr. Greer has previously testified in these consolidated cases; that he has been qualified as an expert witness in petroleum engineering; and that he's under oath.

MR. DOUGLASS: We have no questions about his qualifications.

MR. LEMAY: His qualifications are accepted.

ALBERT R. GREER,

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. CARR:

Q Mr. Greer, you were present when Mr. Hueni presented Mallon -- or Gavilan Pool Exhibit Number Twenty-one, which is another depiction taken from your rainbow map, is that correct?

A Yes, sir.

Q And you were present when Mr. Hueni discussed the pressure in the B-18 Well and suggested that perhaps it was as high as it is as depicted because it was taken shortly after there was injection in that well?

A Yes, sir.

Q Have you prepared an exhibit which shows the actual pressure information for the B-18 in and around the time indicated on this exhibit, being November 19, 1987?

A Yes, sir.

Q Is that contained in Benson-Montin-Greer Exhibit Number Four?

A Yes, sir.

Q Would you please refer to that exhibit and review the pressures that were actually measured in that well at this particular time?

A Yes, sir. As I understand --

MR. PEARCE: Bill, may I ask, what is that?

MR. CARR: This is Exhibit Twenty-one, which is the modified version of the rainbow map. Perhaps it would be helpful to advise the Commission that we have consolidated both direct and rebuttal testimony. We're going to be working back and forth and yours should be numbered (not clearly understood).

MR. DOUGLASS: Is that Exhibit Number Four?

MR. CARR: It's Exhibit Number Four. It's entitled <u>Surface Pressures C.O.U. B-18.</u>

A Excuse me, there are some extra copies.

MR. CARR: We have some extra copies if you need them.

MR. LUND: Thank you, sorry.

Q All right, Mr. Greer, would you now refer to Exhibit Number Four?

A Yes, sir. It's my understanding that Mr. Hueni adjusted the B-18 pressures down because he understood that the pressure in the B-18 was measured immediately after injection, but in addition the B-18 had shown interference from the next nearest well to the west, the K-13, and since it showed interference he assumed that the pressures would be equalized.

But the fact of the matter is that this is one of the areas that is really tight; in fact, it's the tightest area in the -- in the project.

We've had a lot of discussion about the tight area, in fact it's so tight it's a barrier, but really the tightest area is up around the injection wells and this particular well, the B-18, the pressure that we measured on it was taken November 19th at the same time as all the other pressures in the November pressure survey, and the pressure was not taken immediately after -- after injection but after a 3-day shut-in, the same as all the other wells.

We have here a schedule of the activity of that well for this part of the month of November and, although I do not have any other dead weight test than the one taken November 19th, we do have the chart, the meter reading, we used to calculate volumes for the -- for this well, so even though it was shut in, why, the meter chart was left on the well and we could tell from the static readings on the chart approximately what the pressure -- what the pressure is.

And we do that in the same fashion as as one calculates by the gas volume, so even though gas is not going through the meter, the meter nevertheless registers the static pressure on the well, and I've shown these readings and what the readings mean in terms of pressure, and the first direct calculation results from a (not clearly understood) pressure.

And we can see from this schedule the highest pressure even while the well was injecting in the early part of November was only about 1770, 60, maybe 70 pounds.

November 19th when the dead weight test was taken it shows 1693 pounds. At the same time the meter reading was only 1677 pounds; our meter was off by about 16 pounds. That's about one percent.

Then November 20th, 21st and 22nd, we injected a small volume. and I can't tell what that was for, but we could tell it was a pretty small volume because the pressure, injection pressure, increased only to about 1713 pounds by the -- by the meter, and adding a 16 pound correction we've got about 1730 pounds.

Then we shut it in on November 22nd and it was kept shut-in for all the rest of the time and shut-in pressures were taken for the length of that and we can see there approximately how the pressures dropped off.

It looks like on November 26th we have about the lowest reading and on November 27th, 28th it shows a little higher reading.

Well, Mr. Chairman, I'm sure the pressure was still dropping at that time and the reason it shows a little higher pressure, I have an idea that that was

pressure and November 27th, 28th, it shows a little higher reading.

Mr. Chairman, I'm sure the pressure was still dropping at that time and the reason it shows a little higher pressure, I have an idea that that was probably a warmer day. These meters are supposed to be temperature compensated but they aren't quite and on cold days they'll read lower than they do on warmer days.

I would judge from November 23rd to November 28th, during that shut-in period, that the well's pressure probably would drop at the rate of about 4 or 5 pounds a day.

But in any event, after five days shut-in, first a three day shut-in, three days with low volume injection, let's see, six days shut-in, the pressure, by meter, showed about 1645 pounds, so the pressure in that well at the time of the survey would be just about, to the inside on the red triangle there, some 30 pounds less than November 19th pressure, but that's about all, and that's the steepest pressure gradient that we have anywhere in the reservoir in that particular well, Mr Chairman. When it was first drilled, it's our best injection well, when it was first drilled and completed it made about -- about 5 barrels of oil a day and about 10 MCF of gas. We knew it was in the gas cap part of the reservoir in communication with the rest of the reservoir, and we needed that well in that acreage in the unit even though it was tight.

We knew that when we continued our pressure maintenance project and pressured up that area, if it were not in the unit that somebody else could perhaps come along and drill and well and take gas out of the gas cap and destroy our pressure maintenance project.

At that time the requirements for wells in the participating area where they had to be commercially productive. This well obviously was not commercially productive, so our unit agreement was amended so that it now reads that we can include in the participating area land necessary for unit operations. It doesn't necessarily have to be commercially productive, and because of that, we were able to bring in land that we needed in the gas cap area, even though it's commercially nonproductive. We needed it to contain a gas cap.

So we had left a big pressure differential, the biggest in the field, about a mile and a half and then 4-or-500 pounds, and yet that well injected like 6-billion cubic feet after the gas for a total injection of 20 years. There's no question that that gas has gone out of the tight block into the reservoir, spread just as I indicated in March, north/south and then it moves gradually east to west; diffuses is the word that I think fits this best. There's a real tight streak in between those wells.

Q Now, Mr. Greer, is what has been marked as BMG Exhibit Number Five a graphic presentation of the pressure information shown on Exhibit Number Four?

A Yes, sir. When this graph was prepared I thought that we'd ended our testing on the 26th and that's as far as those pressures go. There's two more pressures on the schedule than shows on the graph, but generally what you see is one more day off the edge of the graph that the pressures would not drop down 400 pounds to the point that is shown on Mallon Exhibit 21.

Q Mr. Greer, is it your testimony then that the point on the B-18, the pressure point is as you depicted in your rainbow map and it should not be lowered as suggested by Mr. Hueni?

A Oh, yes.

Q Mr. Greer, we're heard a lot in this hearing about how gas injection is not working and doesn't work with gravity drainage. Are you aware of situations where in fact it is?

A Yes, sir.

Q Would you refer to Benson-Montin-Greer Exhibit Number Three (sic), identify this and point out the relevant portions of this exhibit?

A Yes, Mr. Chairman. This is a paper on the Bahrain field which I found very -- very interesting. It has a transmissibility about like Canada Ojitos Unit.

Q Before we go on, that is marked Exhibit Number Six, not Exhibit Number Three.

But what we wanted to show here is that there are occasions in which gas injection and pressure maintenance has been successful and what I found of particular interest is on the last page, Conclusions, Conclusion Number 2, and it says, "Gravity drainage as well as the oil wettability characteristics of the rock have been conducive to a higher oil recovery by gas than by water."

And, actually, what happened in part of this field, Mr Chairman, the natural water drive was allowed to operate and oil recovered that way. Then they introduced a gas injection, drove the water back down, and found that they recovered additional oil in the area that had been swept by water.

And it's just a higher efficiency of gas injection and gravity drainage that permitted that, and I think it's very interesting to know that at least some places you have records of gas injection and gravity drainage working very effectively.

Q Mr. Greer, you were present for the testimony of Mr. Elkins, were you not?

A Yes, sir.

Q And what was your reaction to that testimony.

A I was, of course, delighted to see Mr. Elkins. It's been forty years since we worked together on engineering committees back in Oklahoma and -- and also I'm delighted to see his analysis of interference tests which I struggled to design and analyze myself some four years ago, I'd like to point out the things that Mr. Elkins has confirmed with respect to the way I've analyzed these interference tests, particularly this one.

Q Perhaps we should go to the three exhibits that are contained in Exhibit Seven and perhaps we should start with Exhibit Seven-A.

A Well, I was first going to discuss some of the things I agreed on first.

Q All right. Okay. Why don't we do that.

A This was real important to me, Mr. Chairman. I have the highest regard for Mr. Elkins and he's an expert in his field, not only in regards to reservoir engineering but particularly interference testing and analysis of (unclear.)

The first thing I note is that he used the EI formula, the same as I did, which, by the way, Bergeson has said in these hearings it did not apply. I don't know what Bergeson's current position is but that's what it's been in the past.

He used under saturated oil, particularly compressibility under saturated oil, which is what I used. Bergeson's observation is that it's saturated, and that makes a tremendous difference in the calculations. Saturated oil has a compressibility like $10^3$ 20 times under saturated oil depending on the pressures, and so at figures for compressibility of oil (not clearly understood.)

Now, for total system compressibility, when I made my study 20 years ago there just was not information of the kind that one would like to have with respect to the compressibility of the rock and I realize that it probably, you know, you have an intuition when you're thinking about a fractured shale, that it's going to have a higher compressibility than anything else, so at that time I -- I used a spread, a high and a low, in making my calculations and we use some different values for the saturation of the reservoir in terms of water and oil and such as that. Overall Mr. Elkins used a compressibility, if my notes are right, he used a (unclear) of 37.5 times $10^{-6}$.

Now, for my low calculation, by low I mean low compressibility which gives high -- high volume of oil in place, I used 25. And for my high side I used 50, and I calculated the results both ways, my high and low, and I decided at that time the only thing I could do about it was probably the best guess or estimate would be halfway between; halfway would be 37.5 X $10^{-6}$.

Mr. Elkins used 35.8. It is heartening

to see someone as experienced as Mr. Elkins agree with me in that total.

Now, he also -- we also agree that -- now this was about a 30-day test, and we shut all wells in the field in and (unclear) 60 days and then conducted the test and -- and he agrees with my analysis that the test results show all the oil in place, not just oil in fractures, but oil -- he perhaps thinks of the -- as far as the storage, is the thickest porosity. I'm not real sure about that. I understood that he's thinking about the fine fractures, as well as that.

My feeling is that it's all fractured porosity, the high capacity system, the tight blocks and the tight blocks are primarily fractures, too, tight fractures.

But now he made his analysis that all of the oil that's represented by this test, based on compressibility of the block and his perception especially of the fractures.

I made my analysis based on his exhibit of the system and the size of the blocks which I have estimated.

So we agree on that. So it is heartening to see his close agreement.

Q Are there other areas of agreement?

A Yes, sir. His final calculation of transmissibility, he gets about the same thing as I did but he got about 2-1/2 times as much oil in place as I did and the reason for that is that Mr. Elkins, not being as familiar with the project as I, selected the wrong well for his well pair and, of course, in a way it's unfortunate we're in this hearing process. I know that if it -- had it not been for the hearing process, Mr. Elkins in studying this reservoir, when he came to this point he would have called and asked me, why in the world did you use the L-11 Well instead of the P-11. Clearly from a cursory examination of this test, one would say that the P-11 Well would be the proper one to use, and that was my thought when we started the test and that's why I selected it as the first well.

But what happened, then, and we put the wells on in series, produced one well for a few days and then we added another well and then later on we added another well. And to explain why the P-11 Well was not the proper candidate in this test, we need to look at Exhibit Seven-A.

Q All right, we'll do that now. Before we do that, Mr. Greer, is this the only point on which you actually disagree with Mr. Elkins?

A As I gathered from his explanation of

his analysis of the interference test, that's the only thing I could see as an area of disagreement.

Q All right. Would you go to Exhibit Seven-A, please, and indicate what each of these graphs show?

A Yes, sir. Mr. Chairman, this graph shows how the pressure would drop at various distances from the well which we put on production. You can see there at the top of the graph at a distance of about 5 miles that no interference would show up there for several days.

At 8000 feet it begins to show up in about one day, two days.

At 4000 foot radius it shows in about two hours; 2000 foot radius quicker than that.

And, you know, Mr. Chairman, that by about the seventh or eighth day the pressures were dropping at the 8000 foot radius, the 4000 foot radius, and the 2000 foot radius, at almost the same rate, not quite, but almost the same rate.

We get out to 30 days and the dashed line, and looking at the upper graph of this display, Plate I, from that time on the radius of drainage in the sense that it reached the field boundary, and the boundary in this instance, which we'll look at a little bit later, is in the edge of reservoir or the beginning of tighter, tighter formations.

At that time, about 31 days, from that point forward, then, the reservoir throughout that area, is in what we sometimes refer to as a pseudo steady state decline, or a steady state decline. All throughout the reservoir the pressures will be dropping at the same rate, 5 miles away, 1 mile away, and even in the wellbore, the pressures will be dropping at the same rate. This is one of the things that makes the use of interference wells most helpful in analyzing the pressure decline in a reservoir and why -- you'll see later on why I like to use pressure differences rather than try to work with absolute pressures.

Now, the thing that happened when we started this test, the P-11 was within, oh, I forget now, maybe a couple hundred feet structurally; now, please remember, Mr. Chairman, this part of the reservoir is where it's fairly steep and dipping, I believe it's 4-or-500 feet and, oh, it's a half a mile or more away from -- from the P-11. The oil in a sense encounters the bubble point as -- see this oil was under saturated and producing. In a sense you could call that bubble point pressure down -- down dip. It's around 1520 pounds of the temperature in this area; the wells have a bubble point at about 1570-or-80 at Gavilan temperature, but this temperature is around 1520, as I recall, and what happened when we put that P-11 on production, it pulled the pressure out of the wellbore down below the bubble point and when it did, then there was an area of saturated oil and a higher compressibility, and, of course, I didn't realize all this until after we got all the information together, but I spent a lot of time in designing this test and trying to figure out the things that I needed to know to be certain that I had a valid test, and, of course, among other things, we got approval of the Conservation Commission to conduct the test and transfer allowables, and such as that, and I realized that one of the things that I needed to look for in this -- this reservoir that was so strange, I had low permeability and those blocks that acted like little individual reservoirs, and yet if you have (not clearly understood) a pressure build-up it will just flatten off rapidly, sometimes in just a few hours.

That told us that we were dealing with a small reservoir.

When we turned around and produced the well, the operating bottom hole pressure would do the same thing, it would level off right quick, so we knew then that even if it was a small reservoir, it was not a closed reservoir. In a closed reservoir, just a few acres, why in just a matter of hours, if not days, why it would be depleted, but instead it would just continue in depth; the pressure, the operating pressure didn't drop. It would just sit there like it was just pumping oil out of a tank. So we had this -- this strange situation and because of that and such a variation, apparent variation, I didn't know what it was until I ran this test, but apparent variation that we watched as we depleted wells and watched the pressures. I felt like I needed to have one really positive check that this test was a valid test and that positive check would be that the pressure in the operating well would drop at the same rate as all the rest of the reservoir.

Well, I got to analyzing and testing to determine that, Mr. Chairman. At that time we were producing these wells with subsurface hydraulic pumps and in order to control the situation, knowing just what we were doing, we would close in the casing and pump all the oil and gas up the production tubing and that way we created a gas blanket from the surface to the pump and then by taking dead weight pressures from the surface, we could tell, even though we couldn't tell the absolute pressure, exactly, because we would have to estimate that weighted column of gas we could tell very closely the difference in pressures and this we did and we found that when we put the (unclear) on and studied its operating history, its operating bottom hole pressure wandered -- wandered down, it didn't do like the rest of the observation wells, and then when I got to studying a few more details, and I realized we'd pulled the pressure down below the bubble point and we had an are of saturated oil by this well, which then, although it seemed to be small compared to the overall reservoir, it would not affect the overall calculation for a different -- for different producing well; it would give high readings, high in a sense of the calculated oil in place.

So when we put the next well on, the L-11, then it was a little more difficult and a little more subjective as to how we calculated the effect of putting the well on on the pressure, but that well produced like it should. It's pressure dropped down and it leveled off and it had a good test.

So I analyzed the L-11. I feel that if Mr. Elkins had analyzed L-11, we would have even gotten closer figures.

I think it might be interesting to the Commission to take a look at some of the details of this test on a graph.

Q And that's what's marked as Exhibit Number Seven?

A Yes, sir.

Q And that's the long --
A Yes.
Q -- it's the long graph.
All right, sir, will you refer to that?
A I'm sorry I don't have a larger display of this but I'd like to point out a couple of things.

The little squares show Phase I, Phase II, Phase III and Phase IV, show which wells were shut-in and which wells were producing during the test.

Now, at this time we did not have the sensitive pressure gauges that are available now, so in order to get a real accurate rate we had to do it with fluid levels and we measured these fluid levels with (unclear) and we would occasionally check the bottom hole pressure to make certain that the density of the long hole had not changed capacity, and we see that on the bottom scale that prior to shutting wells in, we're producing, oh, like 1000 to 1500 - 1200 barrels a day, and in April we shut-in, I believe, the A-14 and as you see, the fluid levels. started measuring them, and they began to build up and then fell off again while producing.

Then the first week in June we shut the rest of the wells in and you can see how the fluid levels there build-up in the observation well until about the 24th of July, in order to establish the gas blanket in the P-11 we produced it for two days and you can see, the response in the observation wells when we did that.

Then, about August the 3rd, we put the P-11 on permanent production, and you can see those little square flags up there at the top of the graph, we felt this test would be so interesting and just so hard to believe the interference in this well in this reservoir, that we asked representatives of the Oil Conservation Commission and the United States Geological Survey, at that time the Department of Interior's representative, to witness these tests. Where you see those little flags is where we had witnesses.

Now, we produced the P-11 with the L-11 as one of the observation wells until about the first of September, and then put the L-11 on and then we can see in September the steepening of the decline of the fluid levels in the A-14 and also in the A-23.

Now those curves are not following exactly the kinds of curves that we calculated on the graphs we looked at just earlier, but in general, they very well confirm what one would estimate.

Then, when I made my calculations, Mr. Chairman, on the consequences of putting the L-11 on production. I noted earlier, it's a little harder and more subjective in terms of just what the response was, but at least we had a valid well to work with.

And so I came up, then, from my calculation of about 6 or 8 darcy feet for transmissibility and then around, taking the average, somewhere around 16 - 1700 barrels an acre of oil in place. And I think from the talk then and the work I've done since then, I'm convinced that was a really -- really a good test, very representative; I mean we didn't have the problems then that we have now in some of these other wells in that you have only a C zone open in these wells so we just have one zone to be concerned with. Also the oil is under saturated. The wells produce by solution gas/oil ratios, and so at that time we just had a really ideal situation to make an interference test.

Q Now, Mr. Greer, can we learn something from this information concerning dual porosity and potential migration across the alleged barrier?

A I think so, Mr. Chairman, and I'd like to at least --

Q Is that information contained on Exhibit Seven-B?

A I'd like to refer still to Exhibit Seven and I'd like to share with you my analysis and my assessment of the drainage situation and by happenstance in the way I feel that gives us insight as to whether or not there's dual porosity in this in West Puerto Chiquito. I don't know about Gavilan but I suspect they're going to be about the same, but at least for West Puerto Chiquito we have what I think is a pretty good country boy type analysis and one I'd like to explain to you.

We can see at the end of 60 days of shut-in that the pressure is still building in these wells. Now that's -- that's kind of a contradiction to the high transmissibility that we calculate, and so that could be only two things in my view.

One, it could be dual porosity or it could be migration from a tighter area. Obviously, I was concerned at that time about it. I, my personal feeling then, was that I just didn't know. I guess, like everyone, you can hope for the best, maybe it really is dual porosity and there's more oil there to get out.

The other calculations that I've made. and, of course, it's a very difficult thing to analyze, that I have concluded that about half of the total volume was in the high capacity fractures. The other would be in the tighter blocks. Again I felt like probably fractured, a little tighter. So here we have a system of high transmissibility. I feel like we've measured all the oil in our test and yet here the blame things are, the pressure is still coming up.

So we assume it's one of those two things, and we had no further information on that until Gavilan was drilled, and, sure enough, there's Gavilan with its lower pressures, and I wonder if we might take a look at John Roe's Exhibit Four?

When the first well was drilled in Gavilan and additional wells drilled, and we project the 11,000 barrels (unclear) decline rate back to zero production, on this graph here we've shown around 1750 pounds, and we felt or I felt, that the other pressures that we had, some of them higher than that; that trend of mine, of course, is kind of an average, not the maximum, however, the virgin pressure in this area at that time should have been right at 1900 pounds at this datum. It appeared to me, and I so indicated in the 1983 hearing that there had probably been some migration from Gavilan area into the unit on the order of 80 to maybe 100 pounds, and then if we look at the graph and see what those 80 to 100 pounds mean on the cumulative production, we come up with something in the range of 700,000 barrels.

So we make just a rough estimate that it looks like we've had 700,000 barrels of migration into the unit.

We'll take a look in just a minute at how -- what that translates into, migration, but I'd like to, while we're talking about dual porosity and migration together, the next -- the next thing that gave us a clue about dual porosity or migration was in the fall of -- September of 1986. At that time the pressures began to draw closer together. We had a pressure somewhere about 14-1500 pounds in the unit; Gavilan had somewhere around 14-1500 pounds, and when we shut wells in then, high capacity wells, they built up in two or three days, leveled off and there was no pressure increase.

So why, when we have a -- when there's a lower pressure, much lower than what we have in the interference test in 1965, greater pressure differential and conversion, if there is oil trapped in a matrix with the differential pressure higher now than it was then, why, why don't we get a glimpse of relative pressure buildup in one of them? We did not.

Now that then lead me to believe that, well, it is migration and it's not dual porosity.

Then a year later when we ran the November pressures, these same wells, and I'm referring now to B-29, B-32, high capacity wells, when we shut them in their pressure built up.

Lower pressure, greater differential and conversion, and now their pressure is built up and the only difference is that there is a differential pressure across tight spots and we've got migration from the unit building the pressure up, so -- so I viewed that as migration and not as dual porosity. That perhaps doesn't mean that there is no dual porosity anywhere but my assessment of it is that that's a pretty good indication that we don't have enough to talk about in West Puerto Chiquito.

Q Are you ready now to go to Exhibit Seven-B?

A Yes, sir.

Q Will you identify that?

A Yes, sir. This is the same formula that (not clearly understood) there's a pressure difference over 20 years of about zero pounds to 300 pounds and I've used 150 as an average. I don't know, 200, 250, using that, we come up with a transmissibility in that area, depending upon the flow system, whether the distance along parallel to the flow is greater than the width. Like, for instance, if it's just as far east/west as it is north/south across this tight streak, then the ratio of the length to the width would be one and it would be about .5 darcy feet would be the transmissibility.

And now, without going into any elaborate calculation as to what does that mean in today's world, we can look at a couple of things.

My analysis there shows, oh, about 100

barrels a day across the (unclear) and I've got three times as much pressure differential now than before and that would be 300, and of course I could have a mistake in these calculations. I worked them up pretty fast and I have not reviewed, but I have an idea there'll be some checks made on them and we'll find out about it if there are.

The key, the key thing now, Mr. Chairman, the thing that our opposition worries about, that I worry about in the opposite direction, our opposition is afraid that there's not much gas moving across the tight streak. I worry that there may be too much.

What happens, Mr. Chairman, when oil was migrating from Gavilan to the Canada Ojitos Unit, the oil was under saturated most of the time. Part of the time -- well, as a matter of fact all the time it was going that direction, and so we're dealing strictly with oil through that system.

Now then coming back the other way, when gas gets mixed up with it, and more gas is mixed up with it because the gas/oil ratio in the A and B zones have picked up, we don't know just how the A and B zone are tied together with the C zone, but the pressures are obviously equalized. When we take a barrel of oil going through a reservoir, replace it with a barrel of gas, then the mobility increases tremendously and we only need a 10 or 20 point increase to take the -- even the .1 darcy feet, to 2 or more darcy feet, chances are that mobility is even more than that.

So if, if, Mr. Chairman, the migration that might exist is this way, then there is adequate transmissibility across that tight streak with the pressure differential to support the production in the expansion area.

Q Mr. Greer, Exhibit Seven-B is therefore evidence of migration, not dual porosity.

A That's my assessment.

MR. CARR: May it please the Commission, we appreciated the comment yesterday about how you have one expert running one direction and another one going exactly the opposite. We're going to try with two exhibits now to explain some of those differences to you.

Q Mr. Greer, were you here for the testimony of Dr. Charles Kohlhaas?

A Yes, sir.

Q And, let's see, we need Exhibit Forty-one. Have you reviewed Dr. Kohlhaas' Exhibit Number Forty-one in which he showed frac treatment responses in certain wells and then examples where there was no frac treatment response?

A Yes, sir, I have.

Q Do you concur in this information?

A I concur in part of what Mr. Kohlhaas said. He said that if there is a response to a frac treatment in a well, that there will be a pulse move through the reservoir and it can be seen on a coordinate scale and he gave as an example one of the wells in which the pressure rises dramatically and then falls back down.

Then he went to another well and we'll pick out the one, I think it's the second panel from the top.

Q Between the C-34 and the B-32?

A Yes, sir.

Q Do you concur with that depiction of what happened?

A Well, there he said that he used the same scale as he did on the other one that showed a response and here he sees no response, and he says that that means there is -- there is no response to the frac treatment.

Now, part of what Mr. Kohlhaas said is true in that the pressure pulse, as it moves through the reservoir will rise up at any point in the reservoir and then come back down.

What's not correct is that for the distance shown between the C-34 and B-32, is that you can see it on a coordinate graph at that scale, and we'll explain why that is.

Q Are you ready to go to Exhibit Eight?

A Yes, sir.

Q Initially, Mr. Greer, would you just explain to the Commission what Exhibit Eight is designed to show?

A Yes, sir, it shows what pressure responses would be at different distances from -- from a well that's been given a frac treatment. It shows how the pressure would rise up and fall off, and the time this -- these events take place, if the characteristics of the reservoir are somewhat like that that we have found with our testing, in this example, and it very closely fits the N-31, E-6 tract where there was about a 6 pound pressure pulse observed in that well, oh, approximately 3000 feet, I believe it was, away from the -- the well that was being treated.

Now what happens as we go a little farther away? The amplitude of that pressure response dies out, falls off, and the -- these curves appear to change. They appear to have a different character, but that, Mr. Chairman, is just because of your perception of the curves. They all do the same thing mathematically. They go up and then come back down.

Now, the 10,000 foot distance is not

quite coming down yet.

Q Now that's the bottom line on the graph?

A That's the bottom line. That's about how far apart the C-34 and the B-32 were. So despite what Mr. Kohlhaas said, we would not expect to see a pressure pulse or a bump out at that distance.

Q Now, Mr. Greer, yesterday I asked Dr. Kohlhaas if he was aware of a rule of thumb as to what would happen in a common -- where all reservoir characteristics were the same, and you have wells, say, twice as far apart as the original test, what would actually happen and was there any kind of rule of thumb.

Does this exhibit show you how you could estimate that?

A Yes, I gathered from Mr. Kohlhaas' (unclear) that he didn't know whether there is a rule of thumb or a direct relation, but there is, Mr. Chairman, a direct relation, and we'll point that out.

Take the first well, the 3000-foot one, and if you'll point it out --

Q This is the top line on the graph.

A There is a pulse there at the red arrow which is about 6 pounds.

Now, if we move the observation well twice as far away, what happens? The response, or the amplitude of the pressure response drops by a fourth; twice as far away, a fourth of the pressure, and we look at that and sure enough, it's a fourth of the pressure.

Now, not only that it's a fourth of the pressure, the peak response comes at four times the first well. The first well shows a response, a peak response, about half a day; the well twice as far away shows it in four days.

Now, the same thing applies as we go on a little farther out, and despite the fact that those curves appear to have different characters, they're all really the same in a mathematical sense, and that -- that relation exists all the way through. Now in my discussing this with Professor Braden (unclear) at Stanford University he pointed out that in view of that relation, that we might find it useful and convenient to prepare a type curve, and that we could prepare, really, one type curve and use it to replace all these and deal with dimensional time and dimensional pressure.

So, so now that we know what to look for, that Mr. Kohlhaas couldn't a pressure response in the B-32 and C-34 fracs, because he didn't use the proper technique to look for it.

So now we'll present how to look for it.

Q That's what's been marked Exhibit

Eight-A.

All right, Mr. Greer, would you identify Exhibit Eight-A for the Commission, please?

A Yes, sir. This is a copy of one of the exhibits, of one of the pressure build ups that we've shown in one of our exhibits at the March hearing, and it shows the pressure response in the B-32 Well when the C-34 was fraced, the response to the fracture.

What -- the way Mr. Kohlhaas analyzed it, was first he said this well had no response to this frac- ture treatment, and to any pressure build up, and of course (not clearly understood). But then he made a Horner log plot, (unclear) and all kinds of (unclear) since. He said, well, there really is a response, although earlier he'd said there's no response, he said, well, there's nothing down there to respond to. But this response is caused by a gravity effect which is sometimes defined as a barrier or a boundary to the reservoir, and I disagree with Mr. Kohlhaas' analysis there. He pointed that out, and said, well, at Gavilan, when you have a boundary that shows up in a build-up test, that even though the slope -- the slope should be 2-to-1. What happens if you have a boundary, Mr. Chairman, the pressure behaves somewhat differently, obviously, than if it had been spread throughout a a large area. Here, if there's a restriction somewhere, then the shape of pressure in time is different, and the way it's different, if there's a boundary or a barrier, you get a 2-to-1 increase in slope, and I pointed out in that connection in one of the tests that we ran, not this one, but here's a 2-to-1 slope and perhaps there would be a boundary and I couldn't tell a difference in analyzing it, was it happenstance or why did it occur within just a few hours of the time of the frac job.

Here, the steepest slope that you can get, right through there, is about 1.3 times the other slope; not 2-to-1, Mr. Chairman, only 1.3.

So that's the first thing, the first clue that we get, that really, that's not a boundary. If it is a boundary, it's a fuzzy boundary; it's not a sharp boundary. You might, perhaps in that area you might have a slight change in permeability value, something like that, but then there are a couple other things.

Q Now, how does this -- what's the significance of this line on this graph?

A Well, that is, of course, the most significant thing. See, Mr. Chairman, we had run a build-up test on that well about 60 days before the frac treatment. I don't even remember why we did it, but it's just one of the routine tests that we take from time to time, and you can see there is no change in the slope of that lower green line graph, which, incidentally, on Mallon's exhibit they had taken note of that part of the graph for some of their markings and perhaps they didn't realize how important it is to me to have that data.

But we see real clearly that there's no change in the slope of that green line.

Now, if there were a barrier, a geologic feature underground, it's not going to change in 60 days; if it was there -- if there was a barrier there in April, it should have been there in January, and it's not there.

Then the third thing, Mr. Chairman, the intersection of the shaded area, that line right there with the beginning slope, I calculate to be about 3 hours from the time we start the frac treatment.

Now, what a coincidence, Mr. Chairman, that this well has been shut in for three days, we don't know when we're going to do the frac job, we plan it for one day, and we hope that we can get the frac job off when we schedule it, but we don't really know that until we do, and what a coincidence that with all these factors, that we go out and frac the well and in three hours there's a response because of a boundary underground. What a coincidence.

So we have those three things to tell me, Mr. Chairman, that's not a boundary; that's the response to our frac treatment.

Q Now, Mr. Greer, utilizing his graphs, Dr. Kohlhaas removed a number of red lines which indicated interference tests between the expansion area and the pressure maintenance area in Canada Ojitos.

Do you think those red lines should have been removed?

A No, sir, they ought to be put back on.

MR. CARR: Could we have Mallon Exhibit Twenty-six?

Q Mr. Greer, we've heard a fair amount of testimony in this case about the recovery efficiency of various pools in this area.

I'd like to refer you to what has been marked as Mallon Exhibit Twenty-six and ask you if in your opinion are the pools depicted on this exhibit appropriate pools for making this comparison?

A Well, I believe there's a lot of similarity in Boulder Mancos, La Plata, East Puerto Chiquito, Verde (sic) Gallup, and West Puerto Chiquito. Otero Gallup I think probably needs to be excluded in that we have reports of two sand lenses in that pool, 6 percent porosity in the sand, and I think it's -- should not be compared.

I think a valid comparison is with Boulder, East Puerto Chiquito, both being high in amounts of gravity drainage, and Verde Gallup has got a lot of gravity drainage, and the reason we're making this comparison, Mr. Chairman, we need to understand the reservoir characteristics and conditions under which these pools were produced.

East Puerto Chiquito is operated by our company. We operate it just as we do Canada Ojitos, to try to get the maximum benefit of gravity drainage. We've not yet started our gas injection and active waterflood. We think there's some Basement oil we might pick up with water there.

But the way we produced that pool, was with the gas/oil ratios, because of the solution gas/oil ratios in up structure wells, we shut them in and just produce the down dip wells to recover the oil by gravity drainage.

So we've got a high recovery in East Puerto Chiquito.

I'd like to look at some of the gravity drainage aspects, particularly with respect to oil wells so we can understand really what the issues are in trying to get maximum recovery from this -- this very unusual reservoir.

Q Now, Mr. Greer, is your comparison of Boulder and West Puerto Chiquito contained in what's been marked as our Exhibit Number Three?

A Yes, sir.

Q Initially, I think it would helpful to start by --

MR. DOUGLASS: Did you say Exhibit Number Three?

MR. CARR: Three, which is the black book.

Q If you will go to Exhibit Number Three, and I think initially we ought to start by just explaining what you really mean by gravity drainage, so we're all together to start with.

A All right. Mr. Chairman, I think if we looked at --

MR. CARR: Just a second. Exhibit Three is the black book. This is Exhibit Number Three.

Q All right, Mr. Greer.

A Mr. Chairman, I'd just like to take the time of the Commission to read something about gravity drainage. It's just succinctly summarized by Frick, and you can see the reference there, in the two paragraphs as follows:

Q And you're on the gray pages that are the first pages in Exhibit Three.

A Yes, sir.

"Gravity drainage is the self-propulsion of oil downward in the reservoir rock. Under favorable conditions is has been found to effect recoveries of 60 per cent of the oil in place, which is comparable with or exceeding the recoveries normally obtained by water drive. Gravity is an ever-present force in oil fields that will drain oil from reservoir rock from higher to lower levels wherever it is not overcome by encroaching edge water or expanding gas.

Gravity drainage will be most effective if a reservoir is produced under conditions which allow flow of oil only or counterflow of oil and gas."

Now, to achieve these conditions, "flow of oil only or counterflow of oil and gas", these are the two things that are important.

"1. This may be attained under pressure maintenance by crestal-gas injection, which keeps the gas in solution, or

2. It may be attained by a gradual reduction in pressure, so that the oil and gas can segregate continuously by counterflow.

3. It may also be obtained by first producing the reservoir [rock] under a depletion-type mechanism until the gas has been practically exhausted,

then by gravity drainage."

Then he says, "A thorough discussion of the many aspects of gravity drainage will be found in the classic paper by Lewis." And we have supplied the numbers and the emphasis.

In our situation we don't have all three choices. We only have two, because as I point out in my next to last paragraph, in this formation once the oil is produced by solution gas drive, then there is not going to be enough oil and permeability, transmissibility left, to affect gravity drainage under any kind of conditions other than might be one or two barrels a day.

So we're limited to Items 1 and 2, pressure maintenance or gradual reduction of pressure.

Now I've analyzed Boulder as to -- you see, Boulder, Boulder was drilled at an opportune time. It was drilled at the time that we still had proration in New Mexico and the wells were restricted in production such that they couldn't produce at excessive rates, and they had capability, Mr. Chairman, for producing. They had high transmissibility wells.

One of the wells drilled by Mobil got out a control when they were drilling. I think they're drilling wet, and it actually flowed some 4000 barrels a day (unclear) till they got it under control. So we know that it's high, high transmissibility, and so we know that Boulder's got lots of (unclear.)

Now, another thing about Boulder, it's about four miles long and a mile wide; four miles along the strike and a mile down dip; ideal situation; short distance down dip to drain and it's a steep dip. So then we put all those things together and we calculated why the conventional Buckley-Leverett equation and with the gravity drainage factor added and those calculations are shown, first, as we pass the blue pages we might take a look at an interesting feature in the pool. The structure is shown on the lower blue sheet. The upper graph shows the pressure production history up through 1966. At this time 75 percent, or so, of the oil had been recovered.

We show there some of the pressures that were taken. Now Boulder initially had under saturated oil and a gas cap. We've found that, Mr. Chairman, in these Niobrara pools it's rather unusual to have under saturated oil and a gas cap but it occurred in Boulder; it occurred in East Puerto Chiquito; it occurred in West Puerto Chiquito; and it occurred in La Plata Gallup. It's unusual in most reservoirs. In this area it's not so unusual.

Now Gavilan undoubtedly had free gas in its highest five wells. The first well produced free gas at a very high rates, so it appears that Gavilan, too, had the strike. Now that's what compares, like in the first line under the date it shows March 1, 1962. The rate was 108 barrels per day per linear mile along the strike but the gravity drainage potential was from 10 to 30 times as high as the actual rate of production.

Then we come down to May of '63, the rate was up to 300 barrels at the lowest; I show the potential as 500 barrels.

Then in '64 the rate was -- production rate was still 300 barrels and now we're getting close to the gravity drainage potential of 10 to 20 darcy feet, but still a very -- the chances are that practically all the production is from gravity drainage, enjoying gravity drainage.

Then in '65 is the first time that there was an increase in gas/oil ratio, and I'm not real sure just how that works in this particular instance, because the gas is helping but then on removal of the oil it causes expansion of the gas cap, I doubt that it seriously hurts that gravity drainage rate that much.

This is the only time we show the gravity drainage rates to be less than the actual production rate, unless, of course, it was higher than 30 darcy feet. It's hard to believe that it was higher than that.

Then when the gas/oil ratio drops off,

why then the production rate fell below the gravity drainage rate. Right here is where you can say the gravity drainage rate increased because of the production rate.

So we know that in Boulder there's a lot of gravity drainage.

Q Okay, could you compare that, compare Boulder to Canada Ojitos as to the percentage of gravity drainage?

A Yes, sir. Mr. Chairman, Boulder was developed and produced at about the same time that we were working Canada Ojitos and I was very much, of course, interested and I spent a lot of time studying and accumulating information on Boulder, and recognizing the high recovery that they have obtained in Boulder and the question was how do we get that kind of recovery in Canada Ojitos. And as we examined the character of the oil, the probable solution gas drive recoveries, the increased volume of gas in solution, the increased shrinkage, it was clear that we could only look to about 6 percent of the oil in place for Canada Ojitos unless we could enjoy gravity drainage.

And there are real problems in realizing gravity drainage where there's a long down dip section, which we had, four or five miles down dip, and when we look at the brown sheets, we can see how disastrous it would be to attempt to produce Canada Ojitos by solution gas drive or like they produce Boulder, they can have no control, they -- they just produce it and thank goodness for the Commission's allowable restriction on rate, why they do manage to get good recovery.

If you restricted our rates, just a simple calculation shows that unless the pressure drops, we just wouldn't be able to produce at any economic rates at all, and we show here what the gravity drainage potential would be under typical solution gas drive conditions in which the gas/oil ratio would increase but the pressures decline and we can see that when the gas/oil ratio got up around 1500 to 2000 cubic feet a barrel and we've only got a quarter of the potential, that (unclear.)

So it was clear to me that if we could do it, we needed to maintain the pressure. We considered water, we considered gas, and as I analyzed that situation I could see that we could maintain pressure with the gas injection as compared to with water injection with approximately 1/50th (not clearly understood) wells without channeling, and that meant to me that we needed to go to, certainly to gas injection, and particularly where we had the situation where we could inject gas with the present structure.

Now on the workover sheet you see one of the only problems that you have in a reservoir where one can try to achieve a gravity drainage recovery, and I show here a section of reservoir 4 miles down dip and a mile wide and a recovery well down at the bottom.

Now, whatever the gravity drainage potential is for that section of the reservoir, say it's 500 barrels a day, but that one recovery well at the bottom can't produce 500 barrels a day, then it's a mistake to drill additional wells.

The additional wells will not increase the gravity drainage potential if there's only one gravity drainage potential for that section of the reservoir.

So, clearly, the proper thing for us to do was to drill wells on the down dip side of the reservoir, inject gas at the top, and any intermediate wells just use them for observation wells.

And in a sense, that's what we've done.

Q Okay, will you now go to the yellow sheet and review that?

A Okay. We have some remarks here that gravity drainage has been ineffective and there have been some general remarks made.

I think Mr. Weiss stated that high recoveries and low gas/oil ratios meant effective gravity drainage and effective pressure maintenance operation, and

I think that's true. If -- if we had only gas injection, pressure maintenance, with no gravity drainage, then as Mr. Elkins said day before yesterday, the gas would just whistle through those fractures and in a short time the gas would reach the bottom of the structure. We need to hold the injection, maintain pressure, and control the rates so that we do not exceed the gravity drainage rate. That's what happens and we know that because of the low gas/oil ratios that we've had, and the large recoveries with those low gas/oil ratios.

I think when we recognize these facts, two important characteristics are evident:

1. A large proportion of the reservoir volume is in the high capacity fractures, otherwise, if it's just a small volume even with gravity segregation, then the gas would soon reach the bottom of the structure.

2. Gravity segregation has been significant because of the large volume in the fracture system, if operating under gas drive would have caused early high gas/oil ratios.

Q Now, does the remainder of this book just contain supporting information?

A Yes, sir.

Q Would you now refer to Benson-Montin=Greer Exhibit Number Ten? This is an exhibit passed out this morning entitled Comparison of Efficiency of Recoveries.

A Yes, sir. Let's see, does everybody have Exhibit Ten?

Here, Mr. Chairman, we've made a comparison of recoveries and I want to say that one way it can be done is to look at the total oil in place and a few other characteristics, and first we'll look at Boulder.

Boulder's cumulative production is about 1.8-million barrels, and I subtracted from that the production above the bubble point. Now the reason for that, Mr. Chairman, is when oil is above the bubble point and the reservoir is produced, then the oil simply expands and at the bubble point, even though you produce some oil the reservoir is still full of oil, 100 percent saturation, no gas, still 100 percent oil.

So the only way we can really, truly compare recoveries and recovery efficiency of the mechanism that's operating, we need to discount the production above the bubble point. So I subtract that, and on line 5 I show that in Boulder they had 1.5-million barrels above the bubble point -- I mean below the bubble point.

Now, the oil in place, line 6, Mr. Chairman, I spent a lot of time getting all the information I could to analyze the oil in place in Boulder, and what I found was the best way to analyze it, I believe if you take material balance calculations, conventional ones are going up against some problems. One of these are these steeply dipping reservoirs, there is a significantly different situation than is typical and ordinarily described in the literature as to how to analyze it, because ordinarily a reservoir is relatively flat, relatively thin, and so as the pressure drops down to a bubble point, there'll be a sharp change; go from under saturated oil just in a short time to saturated oil and you have have a sharp change in those conditions. You can calculate rather accurately with your material balance methods what you're dealing with.

Now here as the pressure drops and the bubble point drops down the structure, then a significant part of the oil is saturated and a significant part is under saturated, until the bubble point goes all the way to the bottom.

Now what I found is that the best way to try to calculate the oil in place is to compare the barrels per pound recovery under one situation with barrels per pound in another situation. By putting the two together, then, we can eliminate some of the unknowns like the free gas cap, which is unknown to begin with. Formation compressibility becomes less of a factor, and so that's how I calculated oil in place in Boulder.

Now the details of that calculation are in the records of the Commission. We filed them, I think, in 1980 in one of the hearings with respect to West Puerto Chiquito.

So Boulder, I would estimate, then, 5-1/2 to 6-million barrels in place, something like 27 to 25 percent of the original oil in place unrecovered in Boulder.

Now in Canada Ojitos the -- under line 1, we've produced 10-million barrels, and here again it's hard to determine what's the production above the bubble point with the bubble point dropping down, down structure, part of it's saturated, part of it's under saturated, so somewhere around .4, half a million barrels, I think is a reasonable number for that.

Then I need to deduct the migration which we discussed earlier, 700,000 barrels there, and we need to deduct the net of the expansion area (not clearly understood) by 1.6-million barrels, I'd estimate about 800,000 of that should be deducted from the pressure maintenance project recovery.

So then we come up to a maximum over the bubble point of 1.5, about 8.1 million barrels.

Now the oil in place in Canada Ojitos is somewhere between 30, initially 30 to 50-million barrels, and I made that estimate some 20 years ago. There's no way to make a more accurate estimate now.

MR. DOUGLASS: I'm sorry, Mr. Greer, I think you said 1.5-million. Did you mean 8.1?

A I thought I said 8.1. Did I say 1.5?

MR. DOUGLASS: I heard 1.5.

MR. CARR: Whatever, which is it?

A Mr. Chairman, it's really --

MR. DOUGLASS; I was listening, you understand.

A Its really heartening, Mr. Chairman, to know that our attorneys are paying that close attention to what you're doing. Sometimes I worry about that.

MR. DOUGLASS: We're always trying to learn, Mr. Greer.

A So, I came up with 30 to 50-million barrels and I say that that's the best estimate that could have been made then or can be made since.

Of course, since that time we've had use of computers come into play, and reservoir simulations and such as that, but there's no way that those methods can improve on this recovery (unclear), that is, that regards the pressure maintenance by gas injection, and if you think about it, on material balance methods, whether you use a computer, slide rule, a calculator, or what, they are based on a pressure response and if, for instance, in a pressure maintenance project you put in just as much as you take out and the pressure stays exactly the same, then there's nothing to work with. It just doesn't have anything to -- no pressure drop to work with.

Now, we had that small pressure drop but these things are out of proportion and -- and so some of the things that undoubtedly creep in, where we have cycled gas so much through the reservoir, it's just the error in computing the volumes of gas; no way to get them perfect, and that alone can cause enough error that there's no way that we can take information since the time we started injecting gas (unclear) oil in place.

Here again I put the details in the record about how I calculated oil in place again in 1984, and I feel comfortable that that's about the range of the oil in place.

Now, there is a lot of Canada Ojitos that has reservoir, as we indicated earlier, that is not commercial, and this volume that I show here for the project area would be the volume in the project area down to the tight streak, and from that 30 to 50-million barrels we show to date a recovery of 27 percent to 16 percent.

And I have the details of how I've estimated the -- the share of expansion area production that should be credited to the unit at the bottom of the page.

Then for Gavilan -- Mr. Chairman, I see it's 5:00 o'clock, I'm just about through and this will probably be a good place to stop when I get through with just this one schedule -- it's had a cumulative production of 4-million barrels, this being approximate till 1-1-88.

Then less the production above the bubble point, which is just about the same amount as -- as migration -- as migrated, and I have migration to Gavilan. Now that's from the expansion area into Gavilan. That's my estimate -- no, I'm sorry, about 500, 4-to-500 barrels of that I estimate came from the expansion area of the unit. The other 300,000 barrels it's apparent to me has come from the south, the west, and the north, and so Gavilan in a sense has been in a pressure sink and enjoying migration from all directions.

The net production from Gavilan is -- when I talk about Gavilan here now, it's about a 27,000 acre section in the heart of Gavilan, but we'll look at it in more detail later.

But for that, that area, that's the volume of oil that we can say was produced from that area below the bubble point.

Now, oil in place, I estimated 30 to 40-million barrels and we'll look at that calculation tomorrow. That gives a current percent recovery of oil in place in Gavilan of 8 to 6 percent; and I would estimate that perhaps a fourth of Gavilan's recovery is from gravity drainage. There's just no way to escape some gravity drainage in this reservoir as high as the transmissibility is.

But it's my feeling at this point the solution gas drive recovery from Gavilan is between 4-1/2 and 6 percent. That translates to 68 barrels an acre and the total recovery from both solution gas drive and gravity drainage, that's the G.D. to date, which is 1-1-88, about 91 barrels an acre.

This is a comparison, Mr. Chairman, of the efficiency of these three pools and it's just so clear to me that the gravity drainage in the pressure maintenance project has been effective and is still working.

MR. CARR: May it please the Commission, at this time we think it would be appropriate to break. We're getting ready to have one short exhibit and then go into the rest of the large books; unless you want to go on for awhile this would be an appropriate time.

MR. LEMAY: No, a good time

for a break for you is a good time for me, so let's reconvene tomorrow at 8:30.

(Thereupon the evening recess was taken.)

C E R T I F I C A T E

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY the foregoing Transcript of Hearing before the Oil Conservation Commission was reported by me; that the said transcript, contained on pages 750 through 989, inclusive, is a full, true and correct record of this portion of the hearing, prepared by me to the best of my ability.

Sally W. Boyd CSR