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

15 June 1988

COMMISSION HEARING

VOLUME 3 OF 5 VOLUMES

IN THE MATTER OF;

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

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

TRANSCRIPT OF HEARING

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I N D E X CONT'D

I N D E X Cont'd

E X H I B I T S Cont'd

EXHIBITS Cont'd

E X H I B I T S Cont'd

MR. LEMAY: The hearing will come to order.

So we shall resume with Mr. Douglass.

MR. DOUGLASS: Thank you, Mr. Chairman.

Call Dr. Charles Kohlhaas.

CHARLES A. KOHLHAAS,

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

DIRECT EXAMINATION

BY MR. DOUGLASS:

Q State your name for the record, please, sir.

A Charles Kohlhaas.

Q What's your occupation?

A I'm a petroleum engineering consultant.

Q Where do you reside?

A In Golden, Colorado.

Q Have you testified before the Railroad -- before the New Mexico Commission?

A Yes, in both cases.

Q Yes, all right. Have you testified before the New Mexico Commission before?

A Yes.

Q All right, sir, and approximately how long ago?

A Oh, I think about thirty years ago.

Q Would you outline your educational and professional qualifications, please?

A Yes, sir. I graduated from Colorado School of Mines as a petroleum engineer in 1956 and I went to work for the Mobil Oil Corporation and I worked for Mobil for several years in west Texas and New Mexico.

I then returned to graduate school and I continued in graduate school and interspersed it with work for the Atlantic Richfield Company for several years. I worked for Atlantic Richfield for approximately 17 years. Obtained a PhD degree from the Colorado School of Mines in geophysics in 1972.

Of interest in this case, perhaps, is the dissertation subject was the effect of variable rock and fluid properties on the behavior of well tests and I was on the faculty of the Colorado School of Mines as a professor of petroleum engineering for twenty years.

I have consulted in various parts of the world and I formed and managed an independent oil company for a short time, which I sold about a year and a half ago, and since then I've been consulting full time.

Q Are you a Registered Professional Engineer in any states?

A Yes, sir, I'm a Registered Professional Engineer in New Mexico, Colorado and Texas.

Q And have you had experience working with what are commonly called fractured reservoirs?

A Yes, sir. I worked with fractured reservoirs in California, Texas Gulf Coast Area, west Texas, southeast New Mexico, northwest New Mexico, Canada, Wyoming, Colorado, the North Sea, the Middle East.

Q Have you made a study of the Gavilan - West Puerto Chiquito Field area and prepared or had prepared under your supervision, certain exhibits and testimony for presentation here today?

A Yes, sir.

MR. DOUGLASS: We submit Dr. Charles Kohlhaas as an expert petroleum engineer.

MR. LEMAY: Dr. Kohlhaas' qualifications are acceptable.

MR. DOUGLASS: Mr. Chairman, I believe yesterday we had a reversal of exhibits. I was glad to report that Dr. Kohlhaas is well today, but he had a bout of food poisoning the night before so we reversed our witnesses as far as presentation is concerned but if you'll just shift those exhibits back we'll start with Exhibit Thirty-nine and I believe his exhibits will be numbered Thirty-nine through Forty-three.

MR. PEARCE: That is the second plastic pocket from the back, Mr. Chairman.

MR. LEMAY: Okay. I'm not sure these exhibits are numbered so that's why --

MR. DOUGLASS: They are not numbered because we didn't know what they might be as we came along, but I will call them out and identify them as we go along.

Q We have identified as Exhibit Thirty-nine a map entitled Well to Well Interference Test Locations.

What have you shown on that Exhibit, Dr. Kohlhaas?

A On this exhibit, on the -- superimposed on the base map which we've been using before, we have a series of dark lines connected between various wells. For the purpose of determining communication and interference and pressure communication in petroleum reservoirs, the common technique is to use what's called an interference test.

Interference tests can be two or more wells, one of which will be designated as the source well and the others are designated observation wells.

The common technique is to put a pressure gauge in the observation wells and measure the pressure during some event in the source well. Now those events can be variable. They're quite commonly the opening and closing, starting and stopping of production in those wells.

In the case of the Gavilan and Canada Ojitos area the interference tests, quite a few of them, were measurements of the response in observation wells during fracture treatments in the source wells.

Q In these you -- excuse me, go ahead.

A We have shown on here in the darkened lines connections between the source wells and observation wells of the various interference tests, the data mostly of which have been presented here previously by Mr. Greer in previous hearing testimony.

Q Is it your understanding that these lines that you've shown connected on 39, the brown lines connected and the green lines connected, are the ones that Mr. Greer has shown that there is communication between those wells by virtue of interference test?

A Yes. The dark brown lines connect the wells which show communication between wells in the Canada Ojitos Pressure Maintenance Area.

The green lines show the wells which demonstrate interference communication between wells in the Gavilan Mancos and the expansion area.

Q Now on the Exhibit Thirty-nine on the board you show some red lines that connect wells across where we've designated the barrier, is that correct?

A Yes. Those red lines are showing the area across the barrier and those are the only tests of all these data which have any relevance to the barrier in question.

Q And is it your understanding that Mr. Greer has represented those red lines as being interference across the barrier area?

A Yes, sir.

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

A No, sir.

MR. DOUGLASS: Offer Exhibit Thirty-nine subject to -- we offer Thirty-nine as shown in your books, Mr. Chairman.

MR. LEMAY: Fine. Mr. Douglass, I have a map different than you show on the board. I don't show the red lines.

MR. DOUGLASS; We're going to take care that in just a minute, Mr. Chairman. That's why

I said we'd like to introduce it the way it is in your book, Mr. Chairman.

MR. LEMAY: Fine. Accepted without objection. Please continue.

Q Dr. Kohlhaas, I believe your Exhibit Forty is a set of pressure graphs, is that correct?

A Yes, sir.

Q All right. What does Exhibit Forty consist of?

A Okay, Exhibit Forty consists of a set of plots and they're in pairs. There are six pairs presented here. The -- part of the pair is -- in each case is a plot of pressure data measured in an observation well. During an interference test the -- one plot is as it was originally plotted and presented by Mr Greer in testimony in previous hearings. The first plot of each pair is those same data replotted all on the same scales.

The original data were presented. The scales were quite different on the various tests. Some of them were quite large or quite small and we just re-plotted them here all on the same scale and the scale that was chosen was the same scale used by Mr. Greer for the first plot presented, which is the response, the pressure measured in the J-6 Well during fracture treatment in the F-7 Well.

Q And where are those two wells on the --

on Exhibit Thirty-nine here?

A Both of those area in the Gavilan Mancos area.

Q All right. F-7 --

A Expansion area, excuse me.

Q All right, F-7 and J-6?

A J-6, yes.

Q Between those two wells and the source of the graph that's the second sheet of each of the pairs is listed showing from what hearing or exhibit those came from?

A Yes. Those are reproduced from Mr. Greer's exhibit book in the hearing of March 17th, 1988.

Q I believe there's one from -- another one that you'll be referring to from the Dugan Exhibit Two in the August 7th, '86 hearing.

A Yes.

Q But I believe the rest are from Mr. Greer's presentation in the 19 -- March, 1988 hearing where he showed that there was -- took the position that there was interference across the barrier, is that correct?

A Yes, sir.

Q Anything else -- well, let me ask you, what -- explain to us that -- that first chart there, what is shows on Exhibit Forty, that is the frac in the F-7 and the response in the J-6, if any.

A We have presented this plot to show the typical response of a well, an observation well, which has good communication and good interference with another well during a fracture treatment.

The F-7 Well was fractured at the time shown by the arrow and you can see that the pressure went up very abruptly and then rather abruptly came down.

Q All right, now that's the pressure in which well?

A That is the pressure measured in the J-6 Well.

Q All right, and what was the status of the J-6 Well at the time before and after and during the F-7 frac treatment?

A Shut in.

Q With a pressure bomb in the well?

A Yes, sir.

Q All right. And do you show here the pressure effect of the frac treatment of the F-7?

A Yes, sir, and it's quite typical. A fracture treatment is a high pressure, high rate, high volume injection of fluids into the well for a short period of time and normally the fracture treatments out in this -- in this area last only a few hours and you can see that the pressure spike here is quite characteristic. It's what you'd expect from that type of a pressure pulse going through the reservoir. It goes up abruptly and it comes down. The slower bleed-off is caused by the fact that the well remained shut-in after the fracture treatment and the pressure must disperse throughout the matrix and the fracture system of the reservoir.

You can see there's a rather long tail off after the initial spike which is probably the bleed-off into the matrix system.

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

A No, sir.

MR. DOUGLASS: Offer Exhibit Forty?

MR. LEMAY Accepted without objection.

Q We've had identified for the record as Exhibit Forty-one a chart or series of charts entitled Gavilan Pressure Tests. What have you shown there?

A Well, here we've shown the -- these are the first presentation of --

Q Excuse me. this should be a foldout sheet larger exhibit. Exhibit Forty was 12 pages long and there should be a map or map of the total area (not clearly understood) that has the Gavilan pressure. That would be Exhibit Forty-one.

Tell us, if you would, what you've shown on Exhibit Forty-one, please.

A All right. What we've done here is reproduced all six of the replotted plots from the previous exhibit, and these six plots are showing the six responses to the various -- the various -- or these six interference tests all on the same pressure scale.

The left two are presented here to show examples from two wells, both in the expansion area, and these are shown here to demonstrate the response of wells to fracture treatments and other wells with which they're in communication.

The upper left example is the one we just discussed. It's the pressures measured in the J-6 Well during the fracture treatment of the F-7.

The second plot on the left, the lower one, shows the pressures measured in E-6 Well during the fracture treatment in the N-31 Well.

Q Let me get those two wells here. Here's the N-31 and the E-6. The N-31 was being fraced, is that correct --

A Yes, sir.

Q -- and the E-6 was being the observation well.

A That's correct.

Q All right, sir. What does that indicate as far as response?

A Both of these indicate good communication between these pairs of wells. We have good pressure communication and interference between them. There's no doubt that these wells are in communication.

Q All right, sir, tell us about the other four tests, then.

A The other four tests are the tests across what has been postulated as the barrier and which we have shown on the map, and which are shown in red on the map.

The -- we examined those pressure measurements. We see that there is no response to any event in another well.

Q Tell us about the first one and what pair of wells are we involved in there.

A All right. In the upper right panel we have the pressures measured in the B-29 Well during a fracture treatment of the C-34.

Q That's this -- these two wells here on Exhibit Thirty-nine, is that correct?

A Right.

Q All right, sir, Do you show on the -- on the graph here when the C-34 was fraced?

A Yes. The C-34 was fractured at the time the arrow was shown there and it's obvious there's no response.

Q Does that -- does the fracture in the C-34 and the pressure in B-29 indicate communication across the barrier?

A No. There's absolutely no communication and no interference between the wells.

Q Should the red tape be removed with reference to those two wells?

A Yes, sir.

Q What's the next chart down?

A The next panel down, it's the second one from the top right, shows the pressures measured in the B-32 Well during the fracture treatment of the C-34.

Q The same well being fraced at this time and a different observation well, is that correct?

A Yes, sir.

Q This one even closer, I believe, --

A Right.

Q -- the C-34.

A Yes.

Q In other words, the B-29 had its pressure -- it was shut-in with a bottom hole pressure bomb in it --

A Right.

Q -- and the B-32 was shut in with a bottom hole pressure bomb in it.

A Right.

Q And the C-34 Well was fraced.

A Right.

Q And the C-34 is across the barrier.

A Right.

Q Did you see any response in the C-34?

A No, sir, there's no response. There's no affect on the pressures in the B-32 Well, indicating there's no communication and no interference.

Q Should that red line be removed?

A Yes, sir.

Q All right, sir, what's your third panel down?

A The third panel shows the pressures measured in the B-32 Well during the fracture treatment of the A-16 Well. Again it can be seen that there's no response, no communication, no interference.

Q Should the red line be removed from those two wells?

A Yes, sir.

Q No interference, is that correct?

A No interference, right.

Q How about the fourth well down here, fourth pair, I mean?

A The last panel shown, the lower right, shows the pressures measured in the A-20 Well during a fracture treatment of the A-16.

Q Two fairly close wells; the closest of all of them, I believe, is that correct?

A Right.

Q Please proceed.

A And again there's no response, no pressure indication here of the fracture treatment, no interference and no communication.

Q Should the red line be removed from those two wells?

A Yes, sir.

Q Now does the Exhibit Thirty-nine that we have on the board, is it the same as the exhibits we passed out?

A Yes. What we have from these pressure measurements is an indication that there's no communication between the east and west sides of that barrier and no communication, no interference across it.

MR. DOUGLASS: Offer Exhibit

Forty-one.

MR. LEMAY: Without objection Exhibit Forty-one will be admitted into evidence.

Q Now, in analyzing pressures can you obtain data and information that can tell you where boundaries or barriers are, not necessarily exactly where they are, but whether they are in the reservoir or not?

A Yes, sir. In fact that's a very common purpose for running a pressure build-up test. And what's known as a pressure build-up in the oil industry, a well is shut in and the pressure change is measured from the time of shut-in through several days, often in some cases many weeks of build-up to that pressure.

The configuration of the pressure build-up curve tells us a great deal about the reservoir.

Q And we've had identified for the record as Proponents Exhibit Forty-two a series of graphs here that are entitled Characteristic Pressure Response of a Boundary as Observed on Horner Plot.

Can you tell us what you've shown on that exhibit, please?

A Yes, sir. In 1951 at the Third World Petroleum Congress Mr. Horner presented a paper which offered the techniques of analyzing pressure build-up in wells.

This was a paper which laid the foundations for pressure build-up analysis in the oil industry and he presented a technique of plotting those data which was very helpful and which has become a standard of the industry, and that plot is named in his honor as the Horner Plot.

In the center upper panel is a reproduction from his original paper. This particular reproduction is in the SPE Monograph No. 1, published in 1967, and it shows his analysis, his original analysis, his original paper of the response of a pressure build-up to a barrier, and this plot shows that there will be a curvature of the build-up between an early period of time and a late period of time. The early period of time will be straight before the curvature intrudes. After the curvature dies out there will be a later straight period on the Horner plot and that those two periods can be connected with two straight lines. The slope change of those -- the slope ratio of those two straight lines is to in the ideal case of the vertical, straight, infinite barrier. In nature --

Q Do you have a -- oh, excuse me.

A Now, in nature we don't normally find that. We don't find barriers that are infinite, straight, and exactly vertical and we find that the ratio change due to most barriers we find in practice will vary from about

1.5 to about 2.5.

Q What else have you shown on this exhibit, Mr. Kohlhaas?

A The left two panels show figures from Dr. John Lee's textbook published by the SPE, showing a similar plot, also on a Horner plot, showing the slope change of 2 and presenting the technique with analysis.

The early period is shown as a straight line. The late period is shown as a straight line and the two are extrapolated to an intersection. The time of the intersection of those two straight lines can be used to calculate the distance to the barrier with the equations shown.

Q What about the panel below the Horner plot here?

A All right, that panel presents a -- is a presentation of the same technique and the same configuration of the plot. This was presented in the SPE Monograph of 1977, prepared by Earlougher and it was an update of the earlier one, which was shown -- from which the above figure was shown.

Earlougher makes the point here that a slope change is not to -- it can be used to interpret the intersection or the curvature of the barrier and he makes the point that multiple faults near -- near a well can cause several different test characteristics, as for example, two tests intersecting at right angles near a well may cause the slope to double and then redouble, or may simply cause a borehole change of slope.

Now that reasoning could be extended to the point that if we divide the slope into -- or the slope ratio into 360 degrees, why we can interpret the curvature and the bend in the fault.

This is discussed in the right panel where the same technique is presented in the Well Testing Manual published by the Colorado School of Mines, authored by me.

Q I see that there are a number of formulas here that seem to have different items in them. Tell me whether essentially they're the same or that they are different formulas?

A They're essentially the same and will give the same result.

Q Have you applied this technique to pressure build-ups in the Gavilan area?

A Yes, sir. In fact, we applied it to wells close to the boundary which we proved in the lack of interference between the tests.

Q Let me, before we get there, let me offer Exhibit Forty-two, if I might, Mr. Chairman.

MR. LEMAY: Exhibit Forty-two is entered into the record without objection.

Q Let me have identified and placed on the board here as Exhibit Forty-three a set of graphs entitled Calculated Distance to Barrier. What have you shown on this exhibit?

A Well, this is getting together presented plots previously presented by Mr. Greer at previous hearings. Three of these are the same as were presented in Exhibit -- the second exhibit, I believe Exhibit Forty.

Q And Forty-one, I -- they were in Exhibit Forty, you're right.

A All right. These are presented exactly as originally plotted by Mr. Greer.

Q In other words, the graphs, the basic graphs and the lines on there except for the -- perhaps the heavy black lines that -- with the red areas there, were on the original graph that was presented in to the Commission by Mr. Greer, is that correct?

A Yes, sir.

Q Did he recognize in each of those a slope change?

A Yes, he noted the slope change and he attributed it to the fracture response.

Q All right, what have you found with reference to the slope change?

A Well, we can see that the shape of these curves is not characteristic. It does not match the response to the fracture treatments, which we -- we had typical cases on the earlier exhibit.

We do see that they match the barrier response, which is presented and is quite typical on the various -- from the various textbooks, and so we -- when these wells were shut in for the interference test, of course, they do constitute a build-up test, whether or not that build-up is perturbed by a response to the fracture treatments.

In this case the build-up was not perturbed by the response to the fracture treatment and so I went ahead and interpreted them as area build-up tests and we can see the slope change here in each case follows the ratio that we normally observe for varying responses, between 1.5 and 2, and we drew the --

Q You said 1.5 and 2.

A 1.5 and 2.5, and in this case we used the early pattern. We extrapolated a straight line through the early time points, a straight line through the late time points to intersect it and we calculated the distance to the barrier.

Q All right, sir, with your first upper

lefthand panel, tell me which well that is, if you would, please.

A That's the Well B-32 and the distance to the barrier was calculated to be 2020 feet.

In the lower left panel we have another test in Well B-32 and in this case the distance to the barrier we calculate to be 1990 feet, quite close to the result in the other test.

Q Let me see, those are two separate build-ups in the B-32 Well.

A Yes, sir.

Q And one of them calculated to show a distance to a barrier of about 2020 feet and the other one 1990 feet, is that correct?

A Right. Right.

Q All right, sir, what's your next -- the panel on the upper right?

A The upper right panel is the pressure measured in the B-29 Well and the distance to the barrier is calculated to be 2610 feet.

Q Approximately half a mile, is that right?

A Yes.

Q All right, sir, and what is the lower righthand panel?

A That's a test of the A-20 Well and the distance to the barrier in that well was calculated to be 320 feet.

Q Do each of the distances that's been calculated in these pressure build-ups approximate the distance from that well to where the barrier had been located in March of 1988 by Mr. Greg Hueni?

A Yes, sir.

Q As far as you know is this the first time these pressure tests have been analyzed in this way to determine the distance from the well to a barrier in the reservoir?

A As far as I know.

Q What's your conclusion then with reference to these four pressure tests measured in three of the wells that are near the barrier?

A Well, the lack of response to the fracture treatment during the interference part of this testing proves that there's a barrier there and the analysis of thee build-ups confirms that barrier, and not only allows us to confirm the presence of the barrier but to calculate the difference the distance to it.

MR. DOUGLASS: Mr. Chairman, we offer Exhibit Forty-three.

MR. LEMAY: Forty-three admitted without objection.

MR. DOUGLASS: Pass the witness.

MR. LEMAY: Mr. Pearce?

MR. PEARCE: No questions. Thank you, Mr. Chairman.

MR. LEMAY: Mr. Lopez, any questions of the witness?

MR. LOPEZ: No, Mr. Chairman.

MR. LEMAY: Mr. Lund, any questions of the witness?

MR. LUND: No, Mr. Chairman.

MR. LEMAY: You first, Mr. Carr?

CROSS EXAMINATION

BY MR. CARR:

Q Dr. Kohlhaas, I'd like to direct your attention first of all to the interference test between the N-31 and the E-6.

A Yes.

Q Could you tell me what in pounds the pressure differential was or how much the pressure response actually was between those two wells?

A I think it was about a pound and a half, two pounds.

Q Okay. Now if you assume that all of the reservoir characteristics stayed the same but the wells were twice as far apart, what would that do to that, say, two pounds response?

A It may or may not disperse it depending on the communication between the wells.

Q So you might see a response and you might not?

A Yes.

Q Would you normally expect to see a difference if the wells were twice as far apart?

A Yes. In fact some of the cases of the tests shown in green here, there are responses to -- to fracture treatments in wells which are much further than that, and they do show a very abrupt response. I think Mr. Weiss showed quite a few of those in his presentation.

Q Is there no rule of thumb that you could use in assuming reservoir characteristics being the same and moving the well twice as far apart as in the actual test information?

A Rule of thumb for what?

Q I mean would it be half -- if you go twice as far do you expect a change in the response, say, a 50 percent change, or is there, in your profession is there any standard that you allude to?

A If the reservoir characteristics were exactly the same?

Q Yes, sir.

A Yes, that -- that response, of course, would be smaller.

Q And do you have any idea what percent or am I asking you just to speculate on something that would just depend on the reservoir?

A It would depend on the reservoir.

Q Now if you look at the pressure tests you can analyze data and you've been able to see a barrier, is that correct?

A Yes.

Q Are you certain that that's a barrier and not just a dramatic change, say, in the permeability?

A Well, that's what a barrier is. A barrier goes from some finite value on one side to zero on the other.

Q Are you sure it's zero or just a change in permeability?

A That is a change in permeability. It's a discontinuity in permeability.

Q But could it be less than zero?

A No.

Q It could not. It is completed to zero in your opinion?

A Well, it couldn't be less than zero.

Q Could it be more than zero? What I'm asking you is does it show a change down to zero, no permeability or could you --

A As I said, that's the ideal case.

MR. DOUGLASS: Excuse me, you need to let him finish his question --

A Excuse me.

MR. DOUGLASS: -- before you start.

Q Could it be just a substantial reduction towards zero but more than that as opposed to showing a complete barrier in the reservoir?

A Yes, it could, but the fact that there's a complete barrier was -- was verified here by the lack of interference of the -- or the lack of response to an interference test.

Q If it was just a pressure test it might show just a change in permeability, not a complete barrier.

A Yes, but the presence of the barrier here is confirmed by more than one piece of evidence.

Q I understand, but if you just look at the pressure test and forget the others just for the purpose of this question, that along doesn't establish a barrier, just a change in permeability.

A It's certainly pretty strong evidence in this case.

MR. CARR: That's all.

MR. LEMAY: Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. KELLAHIN:

Q Dr. Kohlhaas, in reviewing Mr. Greer's work on the frac pulse information and his graphs in which he concluded there was communication across the barrier, what were you provided to study out of Mr. Greer's work?

A I was provided the exhibits from the previous hearings?

Q Were you provided the transcripts of those exhibits?

A Yes, sir.

Q When you talk about the previous exhibits from the previous hearings what specific exhibits were you provided from what particular hearing?

A I was provided the exhibits from the March, 1988, and some from the -- it was in 1987, I don't remember the date, April, 1987?

Q The April/March, 1987 hearings you were provided the exhibits from that hearing from Mr. Greer's work?

A Yes.

Q And you were provided his exhibits from the pressure maintenance hearing in May of this year on the expansion area issue?

A Yes.

Q Were you provided with any of his transcripts, testimony and exhibits from any other of these hearings with regards to this subject?

A No, sir.

Q Did you review, in doing your work, Mr. Greer's testimony and explanations and interpretations of his exhibits?

A Yes.

Q Thank you.

MR. LEMAY: Additional questions of the witness?

He may be excused.

MR. DOUGLASS: Call Mr. Powell.

A Thank you.

MAX F. POWELL.

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

DIRECT EXAMINATION

BY MR. DOUGLASS:

Q Will you state your name for the record, please, sir?

A Max F. Powell.

Q What's your occupation, Mr. Powell?

A I am a consulting petroleum engineer.

Q And how long have you been a consulting petroleum engineer?

A Well, for quite a long time. I --

Q Or an engineer?

A Well, an engineer since June of 1949, or approximately 39 years.

Q All right, sir, do you have a degree in engineering?

A I do.

Q From where and when?

A From Texas A & M in June of 1949.

Q What's been your professional experience since that date, briefly?

A Following graduation from Texas A & M I was first employed by what was then called Halliburton Oil Well Cementing Company but I had nothing to do with cement. I was in the electrical well surveying division of Halliburton and in that capacity assisted in running those kind of surveys in open hole well bores including, but not limited to electric logs, temperature surveys, caliper surveys, taking sidewall cores, and things of that nature.

I left Halliburton effective November 30, 1949, and accepted a position with the Railroad Commission of Texas, which is the oil and gas regulatory agency for the State of Texas, in its District IX office, located in Wichita Falls, Texas.

For approximately two years I was involved primarily with field testing of both oil and gas wells and some reservoir evaluation work.

On October 15, 1951, I was transferred by the Railroad Commission to its headquarters office located in Austin, Texas, and there I was assigned the job function of Technical Hearings Examiner. In that capacity I presided over approximately 800 technical hearings for the next one and one-half years and following the evidentiary phase of those hearings I reduced the testimony and evidence to a document referred to in those days as a Memorandum to the Commission. I recited what I felt to be the prevailing testimony and evidence. I made findings of fact and recommendations to the three Commissioners regarding ultimate disposition of the issues.

Q Did the three Commissioners actually hear the hearing record itself or sit in on the hearings?

A No, they did not.

Q They didn't conduct the hearings, is that correct?

A No, that was my function.

Q And why didn't the three Commissioners perform that function such as the three Commissioners are doing here, Mr. Powell?

A Well, the Commission heard many cases. There were nine dockets per week, beginning at 9:00 o'clock on every morning of the week except Monday. Monday morning would have been reserved for conference time and that's when the Examiners met with the Commissioners and that was decision time.

It included dockets set at 2:00 p.m. on every afternoon of the week, so there were nine dockets and mostly there were eight to ten cases considered on each docket and that would have been overwhelming, I think, for the three Commissioners to be involved with the Oil and Gas Division to that extent in hearing all of those cases.

In addition, the Commissioners had other divisions, such as the Motor Transportation Division, the Railroad Division, the Rate Division, the Liquified Petroleum Gas Division, and now for the last considerable number of years, the Surface Mining Division, and all of those divisions have on-going issues before them that the Commission takes testimony and evidence through the hearing procedure.

Q What -- after that initial Hearing Examiner period with the Railroad Commission, what did you do?

A I resigned in June of 1953 and accepted association with a consultant in Austin, Texas, by the name of Joe Ballenfont (sic), and I worked with him for three years and we did reservoir studies and primarily but not exclusively, we appeared a great deal on behalf of various oil and gas producers before the Railroad Commission Hearing Examiners and presented testimony and evidence.

We did, and I did, appear on an infrequest basis in both State and District Federal Courts.

I resigned the position with Mr. Ballenfont in June of 1956 and established independent consulting engineering offices in Austin, Texas, doing essentially the same type of work that I had been doing the preceding three years with Mr. Ballenfont.

In June of 1957, one year later, I accepted employment by what was then my better client and generated approximately 50 percent of my prior year's revenue, by the name of Russell Maguire, M-A-G-U-I-R-E, who was an individual who lived in Greenwich, Connecticut. He had offices in New York City, but the oil and gas properties that he was engaged in were operated out of Dallas, Texas.

I moved to Dallas, Texas, in 1957 in June, with the beginning title of Chief Engineer, but that wasn't significant, I was the only engineer there for awhile. The -- in that capacity I would -- I had sole responsiblity and supervision of all drilling activity, wellbore evaluation activity, decisions with respect to whether to do additional open hole evaluation testing and finally, the ultimate decision as to whether or not to set casing and make a completion attempt.

Following the establishment of commercial production, it was within my responsibility to market all oil and gas or condensate that would have been produced. Oil and condensate I always marketed under verbal agreements. That was never the case with respect to gas, even casinghead gas. It was always done under contract and predominately long term contracts, which I negotiated and reduced to writing.

My job function, or job title, rather, was subsequently changed, perhaps in the early 1960's, about 1961 or 2, to Production Manager. It was -- it was for cosmetic purposes only; it had nothing to do with my job responsibilities; they remained the same, but by that time I did have the beginnings of a staff. I had two full time engineers, one who helped me with respect to the daily drilling activity and most often we had between 10 and 15 drilling rigs operating around the country and that was a pretty major involvement.

I had another engineer who helped me with the secondary recovery projects that had been initiated and by that I mean that when I joined Russell McGuire, he had a large number of properties scattered over predominately six southwestern states, being Texas, New Mexico, Kansas, Oklahoma, Louisiana, and Mississippi.

There were a large number of wells and field areas that were in need of secondary recovery application. A lot of those properties were studied, primarily by me in the early years, with the result that I put together and operated 23 unitized secondary recovery projects ranging from the smallest one, a 15-well waterflood operation at a Gunzite (sic) sand depth of 600 feet, to a high pressure gas cycling project involving surface pressures of approximately 8000 pounds per square inch at a depth of 10,000 feet.

Q Approximately how many wells were involved in your operations with Mr. McQuire?

A Towards the end of the operation there were more than 600 producing oil and gas wells within the operation.

Q How long were you with Mr. Maguire or his estate?

A I was with the combination Russell Maguire and the Estate of Russell Maguire a total of twelve years. Russell Maguire died in November of 1966, and approximately two and a half years were used to liquidate the oil and gas assets of his estate, and that was accomplished on May 1, 1969, and my -- my position ceased to exist at that time because the company ceased to exist at that time.

I left Dallas at that time and returned to Austin, Texas, and reopened offices as a consulting petroleum engineer, realizing that I had been out of the field in that capacity for twelve years, and what had been my clientele earlier would certainly have found other talent within that time.

I was prevailed and encouraged by the Railroad Commission, two of the Commissioners, the Chief Engineer, and the Chief Technical Hearings Officer, to rejoin the staff of the Railroad Commission as a Senior Staff Engineer, which I did beginning on November 5, 1970. I was in that capacity where I again was a presiding Hearing

Examiner. I did that work for four years, until September 1, 1974.

I suppose the major, or one of the major matters that I would have heard during that time was an allocation formula dispute on the Yates Field, which is, perhaps, now the remaining -- the largest remaining reserve oilfield in the lower 48 states in that it at that time had about 1.5-billion barrels of remaining recoverable oil and there was a major dispute about the Railroad Commission's allocation formula on how the daily production was allocated to the various competitive tracts.

That hearing was convened in April of 1970; it was in continuous session for six months, five working days per week. It generated 15,000 pages of transcript; over 1400 technical exhibits; it was a major undertaking and consumed a great deal of my time for the first year and a half with the Railroad Commission.

Q You said April of '70.

A Excuse me, I -- the year would have been wrong. It was April of 1971 through -- and it was concluded in October of 1971; the evidentiary phase was concluded, not the case.

I left the -- resigned my position with the Railroad Commission effective September 1, 1974, and re- opened offices in Austin, Texas, as a consulting petroleum engineer and I have remained in that practice continuously since that time.

Q Are you a Registered Professional Engineer?

A I am.

Q Have you attended or participated in a number of regulatory hearings during your career?

A Yes, I have.

Q How many would you approximately estimate you were involved in?

A I have no actual count but considering the involvement both as an Examiner on two different periods of time, 1951 to 1953, and from 1970 to '74, and then then the consulting years from 1953 to 1957, and again from 1974 to the present date, I would -- I would believe that the number of regulatory hearings in which I've been involved in one capacity or the other will have been perhaps at least 3-to-4000, and perhaps as many as 6-to-8000.

Q For instance, in Texas, as opposed to New Mexico, does Texas space a described area as being a particular field?

A No.

Q What is the standard for determining what is a field in Texas?

A The standard for determining what is a field in Texas is that rules are adopted for a field identity, which addresses a common reservoir or a common source of supply regardless of the geographic boundaries. For example, that field identity and rule adoption might very well go with the discovery well, and most often does, and as development occurs and additional wells are drilled, the rules follow wherever that common source of supply goes.

Q What is you have three or four separate reservoirs in the same area or same wellbore where wells are completed in separate reservoirs? Are all -- are they classified all in the same field, or is that, say, four separate fields as far as the Railroad Commission is concerned?

A If there were four separate sources of supply separated vertically in a common wellbore, they would each be given a separate field identity. Most often that is done with a parent name or a common name and the reservoir is identified parenthetically

Q In your experience in regulatory hearings in Texas is the issue of whether it's a common source of supply or common reservoir one that comes up very often?

A Yes, it does.

Q Would you say it's one of the more frequent fights and occurs as far as the Railroad Commission is concerned, or one of its more frequent issues that the Commission has to determine?

A Yes. The -- the issue of commonality of reservoir and whether or not there is one or more common sources of supply is, perhaps, one of the most frequently heard issues by the Railroad Commission.

MR. DOUGLASS: I would tender Mr. Powell as an expert reservoir or petroleum engineer.

MR. LEMAY: His qualifications are acceptable.

Q Mr. Powell, have you made a study of what has been designated as the Spraberry Trend Area Field in Texas?

A Yes.

Q And have you submitted to the Commission here, I believe today, three exhibits and a fourth one to add with reference to that particular study?

A Yes, I have.

Q May we have identified for the record in your book, I think they were in the back of the book in a -- most of them in a packet in the back. There are three exhibits. The first is Exhibit Forty-four; yes, I've got it marked. It's Forty-four.

Exhibit Forty-four is a tabulation entitled Statistical Analysis, 1968 & May, 1988 Oil Proration

Schedules.

Mr. Powell, will you tell us what you've shown on Exhibit Forty-four, please, sir?

A Exhibit Forty-four is a one-page document entitled Statistical Analysis 1968 & May, 1988 Oil Proration Schedules, Spraberry Trend Area Field, Railroad Commission District 7-C and 08. I might mention that the Spraberry Trend Area Field is a major geographic producing area. It covers the large majority of five fairly large counties in Texas, in west Texas. Two of those counties happen to be located in Railroad Commission District 7-C. The remaining three of the five counties are located in Railroad Commission District 08.

Reports are made to the Railroad Commission by districts, so it's necessary when one is analyzing or looking to a Spraberry Trend Area Field to accumulate data from both districts or the entire picture will not have been reviewed.

Q Mr. Powell, do you -- do you know of any oil field as far as area is concerned in the State of Texas that's larger than the Spraberry Trend Area Field?

A No, not in terms of -- of present -- present area. I think perhaps Spraberry Trend Area will be the largest geographic area within the state.

There are others with much larger

reserves but not area.

Q All right, sir, what else have you shown on Exhibit Forty-four?

A On Exhibit Forty-four, going to the bottom of the page and the underscoring August and December, 1968 Oil Proration Schedules, I have set out in tabular format, looking to the lower righthand corner under Combined Districts, I won't refer to the individual district separately, I show that in August and December, 1968, the Railroad Commission had on its oil proration schedules a combined District total of 3,659 oil wells.

Of that total number of wells, there was involved in secondary recovery operations, and by that I mean leases or units, unitized areas that had been created for that purpose, a total number of 2,031 wells. Stated another way, almost 40 percent of the total -- excuse me, I should say that another way -- almost 50 percent of the total wells in the Spraberry Trend Area at that time were involved or on leases or units that were looking to or engaged in secondary recovery operations by the injection of either fresh water, brackish water, or salt water.

Q Mr. Powell, you took two different proration schedules there. Is that because of the District 7-C and the District 08 schedules were printed at different times as far as the Railroad Commission is concerned?

A That is correct. In those years the proration schedules for a District are fairly thick and cover literally tens of thousands of wells and they do not all issue simultaneously because of just the huge task of processing that much data. So in those days, before the advent of data processing equipment, it was all hand done and the proration schedules were staggered during the year with the result that they had different dates of issue.

Q Mr. Powell, is my mathematics correct of the 3659 wells, if 2,031 were involved in unit secondary recovery projects, that's over 50 percent?

A Yes, and if I stated that wrong or as "almost", I was incorrect, thank you.

Q What else have you shown with reference to the Spraberry Trend Area Field as far as the current situation is concerned?

Q Well, the current situation being described as the data contained on the Railroad Commission's May, 1988, Oil Proration Schedule for both District 7-C and 08, I won't go through all of the lines of data shown with reasonably good detail for the two districts, except to state that the total number of wells during the intervening 20-year period from 1968 to May, 1988, had increased from 3,659 wells to 8,171 wells, which is an increase of than

100 percent in total number of wells.

Q You're talking about -- excuse me, go ahead.

A During that same interval of time the number of wells on leases or units that were involved in secondary recovery projects will have declined from a 20-year earlier period of 2,031 to a May, 1988 numerical value of 1,211, which is a substantial decline in wells that were involved in secondary recovery even though the total number of wells in the field, and thus the candidates, or potential candidates for secondary recovery, had more than doubled during that time.

Q What is the total assigned acreage in the Spraberry Trend Area Field as of May, 1988?

A That is shown on one of the lines of data approximately midway from top to bottom on the right-hand column. It is 1,034,471 acres.

Q How many acres are not in secondary injection programs (unclear)?

A Well, the vast majority of the acres are not in secondary recovery projects and that number is shown in the extreme righthand column, the third line of data from the bottom, and the value is 876,334 acres.

Q I see on this schedule that there appears to be one gas injection well. Did you investigate to see if there is a gas injection well or if that was a gas injection well?

A Yes, I have.

Q And what did you determine?

A I found that we reported the data in summary form on Exhibit Forty-four exactly as it appeared on Railroad Commission documents.

I had reason to suspect that there was no on-going gas injection well in District 08 in 1988 and I looked to it further and I found that that well was operated by a brine sales company. It is a commercial salt water haulers company and the well number on the proration schedule had a 1-G, intending to represent gas injection, whereas it should have said 1-D, which is a salt water disposal well. I had confirmed that that is an error upon the Commission schedule but I didn't want to change it on my Exhibit Forty-four because it has not yet been printed and the correction made by the Railroad Commission.

Q Anything else you wanted to -- you will have some later data and information on the status of gas injection projects that has occurred in the Spraberry Trend Area Field, is that correct?

A Yes, that is correct.

Q Anything else you want to add at this time, at least, with reference to Exhibit Forty-four?

A No, sir.

MR. DOUGLASS: We'd offer Exhibit Forty-four.

MR. LEMAY: Exhibit Forty-four accepted into the record without objection.

Q May we have identified for the record the bar graph which will be red and blue in most copies. It may not be colored in some that we passed out.

Tell us what you've shown on Exhibit Forty-five, please,

A Okay. Exhibit Forty-five is a graphic presentation of some of the data shown in tabular form on preceding Exhibit Forty-four.

On the lefthand these are two vertical bars. Each has some red coloring and some blue coloring. The lefthand bar has -- is representative of the total number of wells shown in red in the Spraberry Trend Area Fields, combined Districts 7-C and 08 in the 1968, and that value is 3,659 wells. As already stated, the number of wells out of that total that were on leases or units conducting secondary recovery operations by the injection of water in 1968 was 22,031 wells, and that value or number of wells is represented by the blue colored portion of the bar on the lefthand side of Exhibit Forty-five.

Referring to the righthand bar, the red

portion is -- has a value at the top of 8,171 wells, and that is the graphic representation the total number of Spraberry Trend Area wells in May of 1988, and the blue colored portion has the value entered on it of 1,211, and that's intended to show that as of May, 1988, only 1,211 wells were on leases or units that were conducting secondary recovery operations.

Between the two bars I have shown the difference in the height of two colors. The uppermost one has a value of 4,512 and that is intended to show and does show that the total number of wells during the intervening 20-year period increased by a numeric value of 4,512 total wells, while concurrently the number of wells that were on leases or units participating in on-going secondary recovery operations by injection of water had declined by 820 wells to a new value in 1988 of 1,211, which is very little more than 1 out of every 8.

Q From that information and your previous exhibit does it appear that you had -- that there were at least 4500 new wells drilled in the 20-year period in the Spraberry Trend Area Field?

A Yes, that is correct.

Q Were there any major pressure maintenance or secondary recovery projects installed during that 20-year period?

A There was not.

Q All right, sir. In Texas do you have forced fieldwide or partial fieldwide unitization for secondary recovery operations?

A No, there is no compulsory unitization authority granted to the regulatory agency.

There is, however, authority resting with the Railroad Commission to approve voluntary unitization.

Q Has it been your experience that generally in Texas that it's the operators seeing that it's economically feasible to carry on a secondary recovery or pressure maintenance project which brings about such a project?

A Yes.

Q What general was happening to the oil price from 1968 to 1988?

A Well, not much between 1968 and 1973, but following the Arab oil embargo in I believe it was late 1973, perhaps November, the price of oil did experience a general trend of increasing prices over that next, oh, perhaps 12-year period to when in 1985 and early 1986 it reached in some areas dollar values in the $30-to-$35 per barrel range.

Beginning in, perhaps, the first quarter of 1986 there was erosion, as I'm sure everybody knows, in the price of oil due, I believe, primarily to over-supply and over-production and excessive market demand by the -- primarily the Arab producing countries.

The prices started declining and got as low in some areas as $10-to-$12 per barrel. That has improved to some extent and the current level is in the $15-to-$17 per barrel range.

Q In an atmosphere of generally improving oil prices in 1968 to 1988, did the operators in this field, with reference, say, to approximately 4500 new wells, feel that it appeared to be economically feasible to put together a secondary recovery project?

A Well, obviously, economics and essentially the price of oil plays an extremely important role in --in motivating or not motivating an operator or a group of operators to engage in secondary recovery operations.

So the environment with respect to oil pricing from 1973, at least, through 1986 was extremely favorable and produced about as good a climate as I've seen in my 39 years of experience under which people who had valid and viable secondary recovery prospects or tracts with those kinds of prospects, the climate was certainly favorable to initiating and engaging in that kind of activity.

I do not see and I do not find that that happened in the Spraberry Field, which probably is -- contains, within the State of Texas, at least, if not a larger area, a tremendously large, unrecovered reserve that is not recoverable through primary operations, and to date has not been significantly added to the secondary recovery through the technique of waterflooding and no recovery has been accomplished as a result of gas injection secondary recovery.

Q Do you recall what your first experience was with reference to the Spraberry Trend Area Field?

A Yes.

Q When and what was the occasion?

A I believe the "when" would have occurred in May of 1952 when I presided as the Hearings Examiner for the Railroad Commission over a hearing that was concerned with whether or not a large number, and I recall 10 to 15 of the individually identified Spraberry fields, and I maybe I should state that the -- what later came to be known as the Spraberry (Trend Area) Field, did not exist in that identity in 1952. That was done much subsequent to that.

Early on there were many, many fields with separate identifies but generally they had the word "Spraberry" and that definition defined parenthetically to the field name.

The issue in May of 1952 was whether a

large number of those previously identified Spraberry producing entities had in fact merged by development and joined geographically to the extent that it was pretty much a given that a large area was producing from a common source of supply and no longer entitled to individual field identity or rules or regulatory treatment.

Those, a large number of those fields were consolidated following recommendation by me to the three Commissioners. Some of them that were sought to be consolidated at that time were not then consolidated but were later consolidated into what is now and for a long number of years, is identified as the Spraberry Trend Area Field.

Q Did you conduct any of the hearings in the Spraberry Trend Area Field or what became the Spraberry Trend Area Field?

A Yes. At least one other that -- that I recall very vividly. It was in August of 1952, and I listened carefully to Mr. Lincoln Elkins earlier to see whether or not his memory was -- or was relatively the same as mine. That was a hearing in August of '52, wherein Atlantic Richfield Company, following successful laboratory testing, sought authority from the Railroad Commission to conduct in the field secondary recovery testing through what to me at that time was a new word that -- the word was "imbibition". I hadn't the slightest idea of what it meant but they soon clued me in at the hearing that it was a procedure that had been developed in the laboratory where due to capillary pressure and attraction, water in the presence of that very tight matrix rock could be imbibed or, to use a word that I'm more familiar with, would be sucked into the pore interstices, and the thing that intrigued me, I guess, the most at that time was the testimony that as the water that was exposed to a fracture face, for example, and being imbibed or sucked into pore spaces, that the flow of oil would be counter-current to that; that there would be water moving in through the pore throats and simultaneously with that would be oil moving out, hopefully towards the fracture system that would be the transport vehicle to get the oil to a producing wellbore.

That -- that put a hickey on me because I wasn't too familiar with that and it seemed that that was a very unusual concept. I'd have to say that I embraced it with a great deal of enthusiasm because I knew at that time that the Spraberry field area, as it later came to be known, had tremendous quantifies of oil that were not going to be recovered through primary operations. I had -- I remember with shock the exposure to the engineering estimates, such as Mr. Elkins', that the recovery from these tight rocks was going to be 7-1/2 percent and I thought that was an extremely low value at the time and I was disturbed a little later that that was an optimistic estimate, that the recovery did not reach 7-1/2 percent of the original oil in place.

So it was obvious that there was a tremendous quantity of oil within the Spraberry rock system that was not going to be attainable or producible through primary methodology and I wanted to be on the side and come down on the side of encouraging and making the regulatory climate such that the operators would have a flexibility to try experimentation and try to achieve some percentage of that oil in place that I didn't see an avenue at that time for secondary recovery.

Q What -- does the Spraberry Trend Area have reputation with reference to being a viable secondary recovery area now in the State of Texas?

A It has a reputation, yes.

Q And what is it?

A Well, it is not one that it enjoys, and I suppose it endures it more than enjoys it. It is that the Spraberry rock is an extremely poor to extremely marginal candidate for secondary recovery operations utilizing water, and that's three kinds of water, fresh, brackish and salt water. It's very poor under that type of secondary recovery and the prospects of secondary through using gas as an injection medium is nonexistent.

MR. DOUGLASS: Offer Exhibit Forty-five.

MR. LEMAY: Accepted into the record without objection.

Q I've identified for the record as Exhibit Forty-six a tabulation entitled Comparison of Secondary Recovery Projects. Tell us what you show on this exhibit, please.

A Exhibit Forty-six is a one-page document entitled Comparison of Secondary Recovery Projects with Total Field Oil Production Histories, Spraberry Trend Area Field, Railroad Commission District 7-C and 08.

It might be well to explain what the concept was and what I intended to investigate with the construction of what is now on Exhibit Forty-six. I wanted to investigate the -- the number of secondary recovery projects that had reported to the Railroad Commission for its biennial secondary recovery booklet and investigation, what those projects had done with respect to injections and certainly with respect to what they had recovered in the way of oil that the operator of each project himself attributed to his secondary recovery operations.

The last one of those published books by the Railroad Commission of Texas was the 1982 issue which covered all projects for prior years up to and including December 31, 1987. Excuse me, I got that wrong, December 31, 1981, the end of the calendar year just prior to publication.

I found from that source that the quantity of oil that had been recovered by the various operators of the units that are shown on Exhibit Forty-six in tabular form is included and set out on the third column from the lefthand side of Exhibit Forty-six, in the column that is entitled "Estimated Cumulative Oil Due to Secondary Recovery to 1-1-82 Barrels". The values that are in that column for each of the identified projects that are in both District 7-C and 08 came directly from the Railroad Commission's secondary recovery book.

There has been no subsequent issue of that book by the Railroad Commission, I suppose due to budgetary restraints, since 1982, so to get any kind of estimate about what has happened with respect to these projects since 1981, it was necessary to go to the Railroad Commission's annual production ledgers and I show those in the next six columns that are headed Annual Production - Barrels over six vertical columns that are also subheaded 1982 through 1987.

Shown in those six columns for each of these various projects in District 7-C and 08 is 100 percent of the production reported by each of those operators to the Railroad Commission. There is no differentiation there between primary production and secondary. I had no valid mechanism in which to break it down so the entire 100 percent production is shown and with no distinction between secondary and primary.

Those numbers were then totaled for each project in the next to last column on the righthand side of Exhibit Forty-six and then each District is totaled and finally below the two-district total there is a grand total which shows that through the end of 1987, or December 31, 1987, the total cumulative oil that could be attributed to the -- as the result of secondary recovery operations in the Spraberry Trend Area Field is 66.4-million barrels. That, as I hopefully will have already stated, is perhaps overstated substantially for the periods, production periods, 1982 through 1987, but the 66.4 could be considered as -- as a ballpark number or at least something that would -- would attest to the upper side of what the value is; it certainly cannot be more than that and in all probability is substantially less.

The last three lines of data at the bottom of Exhibit Forty-six show the total production of oil from the Spraberry Trend Area, and this would be inclusive of both primary and secondary for the two Railroad Commission Districts, and the grand total has been shown as the bottom-most or foremost line.

And then the annual production is shown for 1982 through 1986. There is no value for the combined two district area for 1987 because that compilation has not yet issued by the Railroad Commission.

But for the three preceding years, beginning in 1984, the grand total was 19.2-million in; in 1985, 20.6-million; and in 1986, 20.5-million; so for my purposes here of trying to get a reasonable quantification of full production and what percentage of that production has actually been secondary, I have assumed 20-million for the calendar year 1987 for the combined total Spraberry Field area.

That then results in a total cumulative, total cumulative oil recovery from the Spraberry combined field area of 570-million barrels of oil.

Q In other words, according to the official Railroad Commission records there's been, and using the estimate of 20-million in 1987, approximately 570-million barrels of oil produced from the Spraberry Trend Area Field, is that correct?

A That -- that is correct and that represents a substantial volume of oil less than I read in Mr. Weiss' preliminary report that the Spraberry had produced about 1-billion barrels of oil, 750-million of which could be attributed to secondary recovery. I find that that is not the case; that the total production, both primary and secondary, is about 570-million barrels, a little more than half of the 1-billion estimate.

Q What did you find with reference to the secondary recovery oil? I believe you gave us that figure awhile ago.

A With the qualification that I believe the -- my estimate of the -- and the Railroad Commission's estimate, of 66.4-million barrels attributable to secondary recovery operations is overstated, especially through the years 1982 through 1987, a 6-year period where I assigned 100 percent production to -- to secondary when I know and am confident that that is nowhere near the case. But even assuming that it was, that's certainly the maximum upward number that anybody could assign, the 66.4-million, even overstated, represents only 11.6 percent of the total production from the combined Spraberry Trend Area, which says, stated another way, that just a little more than one barrel out of every ten that has been produced can be attributed to secondary recovery.

Q Assuming 11.6 percent additional recovery from the field area by instituting the secondary pressure maintenance projects, in other words would that be considered economic just in normal parameters concerned?

A Well, I suppose if one were to analyze whether it's economic would need to look to an individual project with respect to recovery costs, and that's a little general for me, but I can conclude that in my experience I never would have considered anything where I anticipated getting 10 or 11 percent of the -- of additional recovery; that's not, in my view, a viable prospect that I would recommend to my company or client to engage in.

Q Have you also examined the Commission records to determine gas injection project status in the Spraberry Trend Area Field?

A I have.

Q And we'd like to have identified as Proponents Exhibit Forty-seven a tabulation entitled Gas Injection Projects Spraberry Trend Area Field, Railroad Commission Districts 7-C and 08.

Would you tell us what you've shown on --excuse me, let me offer Exhibit Forty-six, Mr. Chairman, I don't believe I did that, if I may.

MR. LEMAY: Exhibit Forty-six admitted into evidence without objection.

MR. DOUGLASS: Thank you, sir.

Q Tell us what you've shown on Exhibit Forty-seven, if you will, please, sir?

A Exhibit Forty-seven is entitled Gas Injection Projects, Spraberry Trend Area Field Railroad Commission of Texas Districts No. 7-C and 08. On my copy that 8 looks more like a capital letter B; it should be the numeric value 08.

I have shown on this Exhibit Forty-seven the operator, lease and unit identity, with respect to some gas injection projects that were engaged in.

The first one listed is in Railroad Commission District 7-C and "Railroad Commission" seems to have come out "PRC"; that really should be "RRC"; a District that is 7-C. The operator is TRI-SERVICE, et al, where on its Rocker "B" lease under date of July 27, 1966, it sought approval from the Railroad Commission to convert six producing wells to gas injection wells on a 17,300 acre project.

There was no subsequent reporting of that activity that I could locate in Railroad Commission files, but I do have the documents on the Railroad Commission's 1968 Oil Proration Schedule where injection wells, and wells of every kind, whether they are shut-in, producing, have an exception to a plugging rule, or they are currently involved in water injection, gas injection, or salt water disposal activities, all of those categories are reported and shown on the Commission's proration schedule.

In 1968 there was not a single one of these six gas injection wells that had been approved for TRI-SERVICE, so there's no doubt that that project was installed, it was very short-lived and resulted in failure of gas injection to enhance oil recovery from that 17,300 acre plot. I characterized that operation as a failure.

The next listing is for Exxon Corporation, also in District 7-C, where on its Pembrook Unit under date of December 9, 1962, Exxon did engage in a gas injectivity test for one well on a 44,154-acre secondary recovery unit.

I'll quote from a Railroad Commission of Texas document, dated February 20th, 1963, which is referred to as a Proposal for Decision. That's a document that a presiding Examiner prepared following the evidentiary phase of a hearing and recites the prevailing testimony and evidence and makes Findings of Fact and Conclusions of Law and recommendations to the Commission.

Quoted in the document I just referred to is the following language:

"... injectivity tests conducted on the unit using the Humble-Pembrook Well No. 6 resulted in break through of gas to the Humble-Penbrook Well No. 4 within 24 hours after injection was initiated. Pembrook No. 4 is about 2200 feet north and 48 degrees east from Pembrook No.

6." The word "failure" out in the righthand column of Exhibit Forty-seven is my terminology and I would describe that injectivity test as a failure in that it did not achieve, not only any kind of sweep efficiency in which it was an aid to the oil recovery process, it was exactly the opposite. It was, in my opinion, at least, an absolute detriment to the oil recovery process in that it filled the fractures with injected gas, the channeling was practically instantaneous within 24 hours, and I don't believe that that gas could be construed as a result of that testing as a vehicle to use in the -- in a fractured formation environment to increase ultimate recovery.

I quote again following that on Exhibit Forty-seven from the same referenced document, as follows:

"A subsequent test using a nitrogen tracer slug resulted in breakthrough of the tracer material to the Pembrook No. 4 after only four hours of injection."

Obviously, that test was not successful and indicating any kind of beneficial result following gas injection and/or a nitrogen tracer, so I ascribed "failure" to that event.

The last one listed is in District 08, where Mobil Producing Texas and New Mexico, Inc., under date of February -- under date of February, 1970, engaged in the injection of gas and it was more particularly defined as plant residue gas; I would often describe that as plant tailgate gas; injected gas into the -- its Preston Spraberry Unit, which comprised a total of 17,038 acres. The injection was initiated in February, 1970, and was permanently discontinued in May of 1970, three months later, and Mobil evaluated the effectiveness of that gas injection short-lived operation as not effective and I ascribed the word "failure" to it, but the word "failure" addresses more the applicability of gas injection as a vehicle to improve secondary recovery in a fractured environment such as the Spraberry rock in the Spraberry Trend Area Field.

Q Do you have an opinion as to whether based on the data and information that is available now it appears that a gas injection project would be successful in the Spraberry Trend Area Field in a fractured type reservoir?

A No. I do have an opinion and my opinion is that several operators have tried more than once to achieve injectivity and I might say that injectivity was achieved and its no real trick; all you need is compression equipment to inject gas. What these operators failed to achieve with the injection of gas was any kind of sweep efficiency where -- where the gas would be beneficial and aid in the oil recovery process.

They not only did not achieve that

desired end result, what they did achieve was even worse in that the data gathered as a result of these injectivity testing for gas indicated that it would be detrimental and the fracture system would be filled with gas, which would block any -- any further drainage of oil from the matrix tight rock into the fracture system to be transported to the wells. So the collection of data was negative.

Q Have you also prepared a series of isobaric maps from Mr. Weiss' report to determine the pressure distribution with reference to what we call the pressure maintenance area, and I assume as a result of this hearing you're familiar with -- with that area, I mean the area that's shown in brown on Exhibit Five and Exhibit Thirty-nine, and the green and slashed green area which we've called the Gavilan Mancos Pool Area or the Expansion Area and the Gavilan Area.

Are you familiar with those two areas as far as this hearing is concerned?

A I am.

Q And have you prepared an isobaric map, a series of isobaric maps, using Mr. Weiss' pressure data that he had in his report, Exhibit Nineteen?

A I have.

Q And is the first one of those dated June 30, '87, Figure 2, page 23 out of that report, and I'll identify it as Exhibit Forty-eight.

MR. DOUGLASS: All right, get my housekeeping done here. We would offer Exhibit Forty-seven, Mr. Chairman.

MR. LEMAY: Forty-seven is accepted without objection.

Q All right. And Exhibit Forty-eight is the 6-30-87 Figure 2, page 23. What have you shown on this exhibit?

A What is basically shown is an isobaric map or that is a map under which an analyst, such as myself, will put values of pressure by symbols representing wellbores and then connect points of equal pressure and that then results in a graphic representation of not only the pressure or value for each of the wells, but the pressure distribution within the source of supply.

This is a very commonly used procedure by engineers and I think even the geologists sometimes engage in this.

The -- I was concerned about seeing a map in Mr. Weiss' report with values representing pressure by these wellbores and then terminology referring the reader to an isobaric map which was utilized to explain that pressure differentials are not uncommon in gas injection or secondary recovery projects, and I certainly agree with --

with the statement. What concerned me was that there was a -- there was an isobaric contoured map used to support the concept, which I find certainly applicable, but there was no such map used to demonstrate the existence of pressure differentials, there were only values assigned to the various wells for the dates on which those wells had had pressure surveys taken.

I thought it would be of major interest to know whether or not the pressure differentials within a given area or a extended over the full east/west span represented by Figure Two on page 23, which is now Exhibit Forty-eight. So I set out to -- to contour those values and connect points of equal pressure.

Before doing that I did discover that there were three pages of pressure data entered on maps, none of them contoured, and that the wellbores on the maps were not consistent throughout. For example, there were some wells on one page and some not on the nest page, or the third, so there was not commonality of wellbores investigated for each of the three pressure survey periods. I attempted to cure that by putting on each of the maps that Mr. Weiss addressed each of the wellbores whether or not it was surveyed on that particular map survey date.

I found that from looking to either preceding pressure surveys or succeeding pressure surveys, that I could make reasonably accurate estimates of what the pressure would have been in that given well that was not on the map had it been put on the map. So I put it on and I did estimate the pressure based on either prior or succeeding pressure results of nearby wells and the well itself.

So by way of explanation, the wellbores that are in sort of freehand, with freehand entries for pressure value followed by the letter capital E and the well number below the wellbore symbol, those represent wellbores that I have put on one or more of these maps from one or more of the maps that are in the group. The idea was to have on each map all of the wellbores that had had pressures taken during any one or more of the three pressure surveys and when it had a value, rely on that; when it didn't have a value, look to before and after and estimate the pressure in that well based on the intermediate activity.

Q Mr. Powell, let me interrupt you just a second. On Exhibit Thirty-nine let's see if we can't just get a general area covered by these pressures on Exhibit Forty-eight. For instance, I see a Wildfire No. 1, that's the northernmost pressure on your -- on Mr. Weiss' map here, I believe, and I'm pointing to that in Section 26 up here.

I see where the westernmost wells appear to be the High Adventure No. 1 looks like in Section 8, and appear to be to the south of that the Loddy down in Section 20, and I'm pointing to those wells. Those wells are on the far west side of the Gavilan area, is that correct?

A That is correct.

Q Now on the east, the easternmost well appears to be K-13, which is the well in Section 13 over in the brown area over here, is that correct?

A Yes, sir.

Q And then to the south, I believe the southernmost well measured is shown as the Boyt & Lola Well, and I believe I'm pointing to it in Section 11 down here, is that correct?

A Yes, I believe that's correct.

Q So you've got bottom hole pressures that were measured during the Commission ordered testing period that generally covered the entire area that we've been concerned with here on Exhibit Five and Exhibit Thirty-nine, is that correct?

A Yes, that is correct, even though Exhibit Forty-eight is on an 8-1/2 by 11 size piece of paper, the geographic area considered by that map is -- is extensive, very large.

Q What did you do? What process did you follow then after you determined these pressures?

A Well, I had been exposed, primarily in this room, to testimony and exhibits suggesting, if not stating emphatically, that there was a barrier or some sort of physical separation between what I'll describe on Exhibit on Exhibit Forty-eight as the eastern 1/3rd and the western 2/3rds; that I believe that those two areas would represent essentially the pressure maintenance area in West Puerto Chiquito, and the Gavilan on the west plus that green and white hachured area in between.

Q I think we call that the expansion area, or proposed expansion area.

A Yes. The western 2/3rds, then, of my Exhibit Forty-eight would be inclusive of the Gavilan plus what you've just stated as the expansion area.

In constructing the interpretation of the pressure values, and again I'll state that I've inserted no values of my own on Exhibit Forty-eight that are in the printed version or format.

Those were taken, as a photocopy of Mr. Weiss' work from his exhibit on page 23, Figure No. 2 . I did add approximately six wellbores, I think it's exactly six wellbores, that will appear on one or two of the successive investigations by Mr. Weiss and I estimated those pressures, and each of the pressures is identified and each is followed by the capital letter E to indicate that that is my estimate and not that of Mr. Weiss.

I contoured those values and I find my first approach was to find the distribution of pressure between what I've heard described as these two areas and whether or not there was a differential grading from high pressure on the east where there has been a long term gas injection, to the primary production area on the west. I'd heard the words that there was a pressure differential in there but I had not seen it; I didn't know where it was, so I wanted to see if I could contour these maps and find whether or not that is a differential, a normal gradation of pressure value from high pressure to low pressure. I found that that was nowhere near the case.

I cannot contour the pressure values which were in the eastern 1/3rd of Exhibit Forty-eight in a common, ordinary means of contouring technique and grade those contours into the values that are in the Gavilan and the expansion area to the west. I find that in the eastern 1/3rd, which is, I believe, the pressure maintenance area, that the pressures are obviously substantially higher going from a maximum of 1504 in the K-13 Well to a minimum of 1402, and that is my estimate based on subsequent pressures in Well No. E-10.

That then requires the construction of the isobar lines or contours in a north/south orientation and it -- the pressure decrease is a little more than 100 psi per inch and that's a measured inch, or scale inch, not so many thousand feet, but an inch on Exhibit Forty-eight on the east part. I could not carry that same kind of pressure difference and decreasing pressure into the western portion, so I contoured the western portion and found that the behavior of the pressure isobars was dramatically different, just amazingly different, than what I was seeing on the east side. seeing on the east side. It is not what I would expect nor, I believe, any other analyst would expect to see in an area where a reservoir is in -- is in pressure communication throughout and there is both fluid communication and thus pressure communication, what I found was that that was nowhere near the case. I had to start erasing some of the my contours from the western 2/3rds of this exhibit because they could not be contoured into nor be symmetrical with the vertical contours on the righthand side, so it was obvious that the -- there was a major change in pressure behavior at some point, a north- south line between Well A-20 on the west and Well E-10 on the east. I stopped at that point and went to the next map and --

Q Let us introduce Exhibit Forty-eight now and go to what you refer to as Exhibit -- the next map, which is Exhibit Forty-nine, which is the 11-19-87 pressure period, pressure test period, Figure 3, page 24.

MR. DOUGLASS: And I will offer Exhibit Forty-eight. This will be Forty-Nine.

MR. LEMAY: It will be accepted without objection.

Q And what have you shown on Exhibit Forty-nine, Mr. Powell?

A Exhibit Forty-nine is my structural -- not structural, isopbaric interpretation of pressures that are shown on a map by Mr. Weiss on page 3 -- excuse me, page 24, Figure 3, of his report on the Gavilan area.

In a like manner, the numbers that were originally printed and the well identities are those exactly as done by Mr. Weiss. The material that will have been added in freehand is mine.

In a like manner, where there was a well that did not have pressure survey under date of November, 19, 1987, I looked to either the preceding exhibit which was for date of June 30, 1987, or succeeding pressure date of February 23, 1988, in order to reach in my view a reasonable estimate of what the pressure was on November 19, 1987.

Exhibit Forty-nine, therefore, contains 15 major pressures that were reported on this exhibit by Mr. Weiss. It has one additional major pressure that I'll discuss later, and it contains five wellbores and pressures on which I have estimated on Exhibit Forty-nine.

The configuration is essentially the same except that if one compared Exhibit Forty-Eight and Forty-nine, you would find that the maximum pressure isobar or contour, from Exhibit Forty-eight was 1200 psi in the Gavilan and expansion area of the exhibit, whereas on Exhibit Forty-nine the maximum isobar or pressure contour was 100 -- 1000, excuse me, 1000 psi, and there was like reduction in the remaining isobars, or contour lines, on Exhibit Forty-nine. That's with respect to the western 2/3rds of Exhibit Forty-nine.

With respect to the eastern 1/3rd, or the righthand 1/3rd of Exhibit Forty-nine, the pressure isobars were almost identical to those on the preceding exhibit, even though it's my understanding that during that intervening time, that the Gavilan and expansion area had produced at what I've heard described as normal allowables or higher rates of production, that seems to me to have had absolutely no pressure impact on the pressure maintenance area. Those contour lines stayed precisely where they were; the values are the same; yet there was about a 200 pound reduction in pressure on the west side in terms of maximum pressures, or the largest isobar on the exhibit.

The conclusion from this work is that it is inescapable that the -- there are two separate patterns of pressure behavior which results in two separate sources of supply and that neither of these two sources of supply is pressure communicated with the other.

Q Mr. Powell, I noticed that the pressure by the C-34 Well of 1395, which appears to be on the wrong side of your 1400 psi line, seems to be pressure slightly in excess of 1400 pounds rather than one slightly less than 1400 pounds. Have you got that well mis-spotted there as far as pressure is concerned?

A No, not in my opinion. I need to explain that and I'm glad you brought that up.

It's -- I had earlier mentioned and then subsequently forgot, but I'd mentioned it earlier in a description of Exhibit Forty-nine, that I had 15 measured pressures plus 1 more that I would discuss later, and I forgot to discuss it.

The one additional measured pressure is for Well No. C-34, is the lowermost pressure in the right-hand 1/3rd of the Exhibit Forty-nine, and the pressure value is 1,395 psi.

That wellbore was not on the -- the exhibit that was originally prepared by Mr. Weiss as his Figure 3 on page 24. It was brought to my attention after I had completed my interpretation of the structural contour lines --

Q You said structure.

A -- excuse me, these pressure isobars, that there was a pressure available for Well C-34 that was contemporaneous in time with the November 19, 1987, pressures that are shown on Exhibit Forty-nine. I was instantly curious about that because it would have, obviously have some impact on -- on the contouring interpretations that I had done on Exhibit Thirty-nine without being aware that such a pressure existed.

I was -- I was very comforted to find that the value given to me after I'd finished my analysis was 1395 psi and that that fell within about 5 pounds of where I would contour it if I had had the value to start with, so I took a substantial comfort at the interpretation of the pressures on the east without that pressure was confirmed the addition of that pressure after the -- I had already drawn the isobars.

That's a little self-serving but that's the way it happened.

MR. DOUGLASS: Offer Exhibit Forty-nine.

MR. LEMAY: Accepted without objection.

Q And as Exhibit Fifty I'd like to have identified the February 23rd, 1988 pressure survey, Figure 4, page 25 out of Mr. Weiss' Exhibit.

Tell us what you've shown with Exhibit Fifty.

A Exhibit Fifty is my construction of an isobaric pressure contour map for values obtained on the date of February 23, 1988, and the base material came from Figure 4, Page 25 of Mr. Weiss' report which has been, I believe, introduced into this record.

The procedure was the same where I had -- where a wellbore was not on this exhibit but that had been in evidence and had had a pressure taken on one of the earlier two, being 48 or 49, I put it on here, and I estimated the pressure from current and prior behavior.

I believe count will show that there are 17 major pressures on Exhibit Fifty and those are the ones that will appear by the wellbores in reproduced print that looks substantially better than the other three, which I put on here freehand. I wanted it to be clear what I had added to Mr. Weiss' work so that one could distinguish the difference.

I then contoured points of equal pressure value and I find that the -- that the general trend of pressure, the pattern of pressure, for these two very separate and very distinct producing areas is the same. There had been intervening production and primary between the date of November, 1987, which was Exhibit Forty-nine and this February 23, 1988 date, which is Exhibit Fifty. The primary thing that I see on the left 2/3rds is that the area contained within the 1000 psi contour, or isobar, had decreased substantially in size and that there were -- there was a general look-alike to the prior survey but at mostly diminished values.

That was contrasted to what I see on the east 1/3rd of Exhibit Fifty in the pressure maintenance area, those isobars, or contour lines, they, with their prior orientation over there, they are in sharp contrast to and dramatically than the shape of the pressure isobars or contours on the western 1/3rd.

It is inescapable that these two areas on Exhibits Forty-eight, Forty-Nine and Fifty are not common sources of supply. They are not fluid communicated. They are not pressure communicated, and there is some barrier or impediment to flow and communication between the two areas.

I may explain that after I had not been able to draw my contours or isobars showing a gradual pressure differential across these three maps from -- beginning on ·high pressures on the east to lower pressures on the west, that simply is not a procedure that's compatible with the pressure values that we see here. It was obvious that there was something that had to be placed in between those two areas where I had to break the continuity in my contouring either going from left to right or from right to left. I simply could not join those two areas. I perhaps mechanically could have done it by stacking contours and drawing those pressure contours in there and cramming all of that substantial 500+ pound differential between these two areas into a horizontal distance less than one inch, and that would have stacked these or compressed the contours on top of each other, and when you find that, any analyist is going to look for an answer to why that has happened; the same thing a geologist does when his contours on top of a producing formation are stacked, are very compressed, and a dramatic change in slope takes place.

The same analysis is done with respect to isobars. When one has to compress those things to an abnormal degree, as I would have to have done in these maps, the answer has to be that there is a major question with respect to communication and commonality of both pressure and fluid transmissibility across that area.

It was only after I had done all three isobaric interpretations that I could conclude that with respect to each of the three pressure times, those being

June 30, 1987, November 19, 1987, and February 23, 1988, that the -- the junction or the lack of commonality of pressure behavior was at essentially the same place on all three of these maps. It didn't move. It was at that point that I drew in, using a light table, the vertical heavy line that is on all three, Exhibits Forty-eight and Forty-nine and Fifty, which I -- I don't know whether to call it a barrier or a fault or whatever, but it is an impediment to communication, both fluid and pressure-wise between the areas that I have investigated for these Exhibits Forty-eight, Forty-nine and Fifty, and I reached the very firm conclusion that if any other analyst worked with these same data in the same manner, I would be surprised if a different interpretation resulted.

Q Mr. Powell, do you think you need 1000 pound pressure differential in order to establish a separation between reservoirs of the sort that you're dealing with here?

A No, absolutely not.

MR. DOUGLASS: Pass the witness.

MR. LEMAY: Let's take a break, fifteen minutes. We'll come back at 10 minutes to 11.

(Thereupon a recess was taken.)

MR. LEMAY: We will continue with the questions for Mr. Max Powell.

Does Mr. Pearce have any questions?

MR. PEARCE: No, nothing today.

MR. LEMAY: Okay. Anybody else on the -- on that side of the fence? Anybody want to ask some questions?

We'll come back then. Mr. Kellahin?

MR. KELLAHIN; Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. KELLAHIN:

Q Mr. Powell, let me draw on your experience before the Railroad Commission, if I might, sir.

Do the rules of the Texas Railroad Commission provide for oil and gas operators to operate a pressure maintenance unit and project in only part of reservoir?

A Yes, in either a cooperative pressure

maintenance and/or injection modem or under partial field-wide unit operations.

Q The rules of the Texas Railroad Commission do then allow the opportunity to put in a secondary recovery project or a pressure maintenance project in only part of a reservoir?

A Yes. The matter of unitization is permissive. The regulatory agency does not have legislative authority to require compulsory unitization. It only has the authority to approve or disapprove unitized projects that are tendered to it for approval.

Q When a pressure maintenance project is tendered to the Railroad Commission that incorporates a voluntary agreement of all those working interest parties and the Texas Railroad Commission reviews that and determines whether or not it is technically competent and feasible to approve the project?

A It does both. It has, under the unitization statute it has what is often referred to as an examiner's 20-point check list, and for the Commission to have access to approving such a unit it must be -- the unit must be in agreement with those 20 points that are raised. In fact, the Findings of Fact are made with respect to each of those 20 points. That's the legal approach.

In addition to that the technical merit

of the proposed project, whether it be for pressure maintenance or secondary recovery, dealing with an essentially depleted primary supply, is looked into.

Q And I take it that the Railroad Commission, in fact, has exercised those authorities and approved such projects?

A Yes. many times.

Q Does the rules of the Texas Railroad Commission provide an opportunity for the pressure maintenance operators and interest owners to receive a credit for the gas withdrawn from the unit and then reinjected back into the project?

A Yes, that is an applied for benefit. It is ore often than not granted, and I assume you're asking with respect to gas injection credit against producing gas-oil ratios.

Q That's exactly right.

A That is a customary practice.

Q And why is that a customary practice to grant an injection gas credit in terms of the allowables assigned to the unit?

A It has to do with either diminishing or minimizing reservoir withdrawals. If -- that is more associated with pressure maintenance type operations than with pure secondary, and I distinguish between those two in that secondary ordinarily deals with essentially depleted oil reservoirs whereas pressure maintenance is involving an on-going primary project.

Q So in Texas we would find, in fact, a reservoir in which part of the reservoir has been approved as a pressure maintenance project during primary recovery and that project is receiving a credit for the injection gas that is put back into the project.

A Yes, you will find that, Mr. Kellahin. You will not find it with great frequency in the circumstances that you have just described. It is more ordinarily found that where gas injection primarily is the injection medium, that you will more often than not have field-wide units formed. Gas is more transitory than is water, obviously, and it tends to put at least the gas in more mobile fashion and it does not honor leaselines very well.

Q That function of giving a credit for the case re-injection is the operation of some conservation, fundamental conservation practices of replacing the voidage in the reservoir with the injected gas.

A Essentially that. It can be either replacing all of the reservoir voidage, in which case you have a true pressure maintenance, no reduction in pressure during the producing phase. It can be partial.

Q As hearing examiner before the Railroad Commission, Mr. Powell, did you have occasion, sir, when you had before you for a decision geologists you knew personally and professionally, both of whom you had high regard in respect for their ability, in which they would take the same structural data points and contour for you on a structure map significantly different contours, and each of those experts giving you a different point of view on how that structure is displaced.

A Does the question go to whether I have had that experience as a regulator?

Q Yes, sir.

A Yes, I have.

Q And as a regulator have you seen geologists that also take the same information and give you an isopach that is significantly different when each of those gentlemen contour that data?

A Yes, but more often than not, when one is dealing with isopachic (sic) interpretations, the reason for variance in configuration of the thickness lines, I found more often than not was associated with the basic data on which they were relying. Some, for example, would isopach gross thickness; others would isopach net thickness and the closer one comes to isopaching the true hydrocarbon pore volume, thee the more opportunity there is for disagreement and dispute about the parameters, such as porosity and the oil and water saturations.

Q When you prepared the pressure isobars on Exhibits Forty-seven, Forty-eight and Forty-nine, you were making contours of the pressure information that is shown on each of those displays?

A Yes, the exhibit numbers are not as you described. They are Forty-eight, Forty-nine and Fifty, but I was interpreting and drawing contours or, stated another way, isobaric lines, connecting points of equal pressure.

Q Let me identify for you on the bas map, Proponents Exhibit Number Five, Mr. Powell, let me locate for you what is the unit well, the K-13. It's in Section 13 here in the main part of the pressure maintenance area. Do you show that on each of your three exhibits?

A I do.

Q And what is the assigned value for the pressure on each of those displays for that well?

A On Exhibit Forty-eight, which was the June 30, 1987, pressure survey, the pressure in Well K-13 was 1,504 pounds per square inch.

On Exhibit Forty-nine, which is the November 19, 1987, pressure survey, the value for Well No. K-13 is 1,508 psi.

On Exhibit Fifty, which is the pressure

survey dated February 23, 1988, the pressure value for Well K-13 is 1,466 psi.

Q Do each of your exhibits show the pressure value for the well in the adjoining Section 18 up here? It's the Unit Well B-18? It's just a little over a mile farther east from the K-13?

A None of the Exhibits Forty-eight through Fifty have a pressure value for that well.

Q Would you assume, Mr. Powell, for the sake of discussion that in each of those instances the pressure differential between the K-13 and the B-18 Well, for the B-18 Well it's approximately 400 pounds higher?

A You're asking me to assume that?

Q Yes, sir.

A All right, I can assume that.

Q Okay. Using the same methodology by which you have drawn the contours of the pressure, the isobars for the Gavilan Mancos area, and applying that to the B-18 Well and the K-13 Well, would that cause you to draw two separate reservoirs for each of those wells if you have a 400-pound pressure differential between them?

A I don't know whether it would or not, Mr. Kellahin. I am not aware of any such pressure as the well that you described. If I had such a pressure, I would analyze it with respect to all of the other pressures and data that I had and reached a conclusion. I can't do that in the absence of a pressure.

Q If I give you a pressure that you assume is 400 pounds higher in the B-18 Well than the information you have on the K-13 Well, can you factor that into the method of analysis you've used and show us whether you have both of those wells in the same reservoir or not?

A Yes, I could do that if you were to -- I do not have the location of the hypothesis well that you're assigning 400 pounds of more pressure to on any of those Exhibits Forty-eight, Forty-nine and Fifty. If I have such a location on these exhibits for the wellbore symbol and you give me the pressure value, then I can. It's not a matter of factoring that in, it's just a matter of interpreting the data.

MR. KELLAHIN: Nothing further.

MR. LEMAY: Mr. Carr, any questions?

MR. CARR: No questions.

MR. LEMAY: Additional questions of the witness?

Mr. Chavez.

QUESTIONS BY MR. CHAVEZ:

Q Mr. Powell, in the testimony that was

presented before you on the Spraberry Pool, did you take a look at bottom hole pressures in that pool?

A You mean with respect to material that's been presented in this record?

Q Well, the record that you recall that was presented to you as an examiner in the hearing of the Spraberry cases, did you take a look at bottom hole pressures?

A I feel relatively certain that bottom hole pressures will have been sponsored both as evidence with corresponding testimony, but that would have been 36 years ago. I have no recollection of what the values were.

Q Just in general, then, would you consider a pressure difference of 500 psi between wells in a pool, shut-in bottom hole pressures, that is, to be indicative that the wells may not be in the same pool?

A Given only the one parameter, Mr. Chavez, I do not believe that a reasonable analyst, and I hope I would qualify as such, would come down with a conclusion on that limited volume of data. I not only looked to pressure differential, I look to distribution of pressure differential and where it is and what the patterns look like before making a decision as to whether I'm dealing with one common source of supply or multiple sources.

Q Would you also take a look at production rates in the areas where the pressures are different to determine whether or not the differences may be caused by a difference in the production rates?

A The, I'll say that where the pressure differential between two given areas is small, yes, I would look to production rates as being impactive and perhaps creative of the differential.

Where -- where the rates are -- or the differences in pressure -- are large, as they are, and I believe it to be between Gavilan and the expansion area and older pressure maintenance area, I do not believe that these -- that rates impacted the pressures even though I did look to that and that is a part of my conclusion.

Q One of the exhibits presented earlier by Mr. Elkins, or that he spoke about, is a paper that he wrote concerning reservoir performance and well spacing in the Spraberry Trend Area Field in Texas.

I'm going to hand that to you and if you will look on page 187, at the top right there is a plotting of bottom hole pressures that were taken in 1952 in the Spraberry and we note that there is a wide variation in pressures just within that small area of that pool.

Could you just glance at that and give an estimation of what the difference is in the pressures in that pool at that time?

A Well, I do not believe that you have accurately described these pressures as having -- on this exhibit that you have handed to me, as coming from a relatively small area. I do not see the area described on --

Q I think the area is described on the previous page at the bottom right, and when I characterized it as "small", I mean it looks to contain three sections.

A I am not able to confirm instantly that the graphic display of pressures on the upper righthand portion of page 187 were in fact taken from the three section area in the lower righthand corner of the preceding page 186, but assuming that it is, perhaps I can respond to your question if you could restate it for me.

Q Okay, just -- even though -- if we don't characterize it as a small area and that those pressures were taken within the Spraberry Pool, what is the difference in pressures measured overall, say, within a range of distances?

A Well, I see overall minimum pressures on this graphic representation on the upper righthand corner of page 187, the minimum pressure is slightly more than 1400 pounds and the bulk of the upper level pressures are just below 2000. There is one that appears to be out of context with the others that's just less than 2200. So there's generally about a 600 pound spread on that graphic representation.

Q Thank you. That's all I have.

A Mr. Chavez, I think it's fair to say to you that your -- as I interpret the purpose of this graphic -- is to demonstrate that bottom hole pressure declined for the period of time that that graphic concerns itself with in shut-in wells in the same proportion that it declined in producing wells.

Q Yes, I understand that. Thank you.

MR. LEMAY: Thank you, Mr. Chavez.

Additional questions of the witness?

REDIRECT EXAMINATION

BY MR. DOUGLASS:

Q Mr. Powell, looking at the interference test that Mr. Chavez asked you about, do you see any trends in those bottom hole pressures that were measured there?

A Yes, I do.

Q Is that one of the tests that you apply to isobar treatment of determining common reservoir or common source of supply is to determine the trends that are occur- ring with reference to the wells that are involved?

A Oh, yes. The trends of the pressures is a major consideration and the exhibit that Mr. Chavez referred me to shows that there was almost equal decline in bottom hole pressure over the period of time considered in the graph from -- between wells shut-in as was experienced by wells that were producing, and that is dramatic evidence of excellent communication.

Q All right, sir. Pass the witness.

MR. BROSTUEN: I have one.

MR. LEMAY: Mr. Brostuen.

QUESTIONS BY MR. BROSTUEN:

Q Mr. Powell, in your discussion of your Exhibit Number Forty-seven, you talked about the performance of several gas injection projects in the Spraberry Trend Area Field and all of the -- there were three projects, all were indicated to be failures.

Was I correct that -- did I hear that you said that not only were they failures, but that gas injection could be detrimental to recovery in the Spraberry Trend Area?

A Yes, you did hear that.

Q And have you evaluated the gas injection and performance in the Canada Ojitos Unit and formulated an opinion as to the effectiveness of the gas injection and whether or not it may have been detrimental to the ultimate production of oil from that reservoir?

A I have. I suppose the preliminary answer to the question, if I could then give that answer and qualify it --

Q Sure.

A -- is that I have not made an independent investigation. I have, however, been exposed to a great deal of information, essentially just prior to this hearing and during this hearing, and I find that the gas injection is essentially high on structure in the unit to which you refer; that there is substantial structural dip from west -- excuse me, from east to west, and the strike of that dip is generally north-south.

In the sense that the gas injection in that unit is very high on structure and is not, in my -- from what I have seen and been exposed to, within the current, or even prior number of years, oil column, I do not believe that it could be construed as having been detrimental to an oil recovery process there because it's not-competing in the fracture system for pressure with the oil from the matrix.

That is not to be compared, however, in my view with injecting gas into an existing oil column where one does not have the structural benefit for the gas accumulation to be on top of the oil. I think that's vastly different on the east side of this area than the west side where there is not that dramatic structural relief.

With respect to whether it's beneficial, if that's a part of your question, I have not made an assessment of that. I have generally expected to see somewhat more definitive analyses done of the success or failure of that effort and that would include knowing what the original oil in place would have been for that unit area; what the oil could have been expected to be realized under primary operations, and by that I mean absent any injection of any kind, and then quantifying of what has actually been achieved.

When one does that, then you have really gotten down to the nuts and bolts and you can say, yes, this project has been immensely successful; it's been moderately successful; or it's been a bummer.

The only reference that I have seen, and I'm not critical of that, it's just an observation on my part, is that there is one well in the unit area that has produced 2-million barrels of oil and that then is taken to support the concept that the gas injection project has been eminently successful. I don't buy that, and perhaps that's just my way of analyzing things, but there's a great deal more to look to before one could say, yes, that it has been successful partially, or it has had little to no impact, and if the only supporting data is one well having made 2-million barrels of oil, that in my view is nowhere near sufficient on which to make an assessment that this project has in fact been successful.

It's a good indicator but it is standing alone, nowhere near sufficient. There's lots more analytical work that certainly is available to this large number of analysts than that. That is not enough.

Q Well, would you, whether or not you subscribe to the re-imbibition theory or not, I don't recall whether you've said one way or the other on that; however, would it appear to you that by maintaining reservoir pressure by gas injection would increase the -- the re-imbibition of oil into the matrix and increase -- result in the counter flow of gas out of the matrix into the fractures and in a sense improve production more?

A I am a proponent of both imbibition and re-imbibition, based on what I've heard in the Spraberry days in the early 1950's and what I have heard from Mr. Elkins and Mr. Hueni in this room.

I am also a proponent of the reservoir engineering concept that in a fractured environment such as I understand exists at Gavilan and the extension area, or proposed expansion area, and perhaps don't refer to that properly, if there is heavy fractures evident there, I believe, and support the concept that the maximum ultimate recovery of oil will be realized by maximizing the pressure differential between the fracture, which is the transport vehicle or the pipeline from the matrix to the producing well. I firmly support that concept and that is not a new position for me; it goes back many years, that ultimate recovery is enhanced by maximizing that pressure differential; stated another way, keeping the fracture pressure as low as possible by producing producing wells to capacity.

That's not to say that I'm not also an advocate of secondary recovery, Mr. Commissioner, I am. I have engaged in it and participated in it to a major extent. I do not subscribe, however, and I am not a proponent of putting to risk known primary reserves in the hope or the expectation of an injection project that might or might not increase the ultimate secondary recovery. I don't believe and I don't subscribe to risking a known for an unknown percentage additional gain. I much more favor the primary depletion process that will yield the maximum ultimate recovery and then put that remaining reserve at risk under a project that is best assigned to handle the circumstances at that time. You're no longer risking the primary recovery; you have that and it's been achieved.

So the benefit of a secondary project at that time can -- can only be on the plus side if it's successful and you don't lose anything if it's unsuccessful except the money to do it.

Q Thank you very much.

QUESTIONS BY MR. LEMAY:

Q Mr. Powell, when your examiners and commissioners get together at 9:00 o'clock is that an open meeting, or not?

A In my days on my two different tenures of duty, Mr. Chairman, it -- we had closed sessions. The public was not only not invited, they were not permitted.

I was attending one conference where a legislator stumbled into the room and asked what was going on and Chairman (unclear) said, "We're having a conference," and the fellow said, "Well, do you mind if I sit in and hear you discuss my application?" And he said, "Not at all, sit right down. We will deny it as the first order of business and then you can leave."

Q I like your democratic process.

A But it is open these days, Mr. Examiner -- Mr. Chairman. The public can attend and they're invited to attend. They do not participate, however, except on extremely rare occasion and only then by invitation from the bench.

Q The Spraberru Tremd, is anyone drilling that any more with $16 oil, except for maybe a few (not clearly understood?)

A To my knowledge there is precious little drilling activity going on in the entire State of Texas and none in Spraberry.

Q What about the average recovery from Spraberry wells? Would you hazard a guess?

A Averages are sometimes misleading, I'm sure that you know, Mr. Chairman. The -- if one were to assign a number just across the board, if you come down with 3 to 5 percent of the original oil in place, you probably wouldn't be far wrong. You're not going to get much more than 5 and you probably won't get much less than 3.

Q Can you translate that into barrels, cumulative barrels of oil per well?

A I have not quantified that. I've looked through a large number of -- in fact every large secondary recovery project and I think the most successful one, and that is the project in which Mr. Lincoln Elkins was involved, and that is SOHIO Petroleum's Driver Unit. In terms of numbers of barrels it has recovered far more barrels than any other secondary recovery project in Spraberry, but I believe that, my memory is that through the end of 1987 those secondary recovery operations by SOHIO, as successful as they were, and only in comparison with other projects could you qualify it as being very successful. The additional recovery due to secondary is substantially less than 3 percent of the original --

Q I guess what I'm trying to get at is I've had some experience with Spraberry, not very successfully, with average cums of 30-to-60,000 barrels per well. I would -- is there a ratio, that you use in applying a waterflood project to the initial primary, like 1-to-1? We tend to gauge that type of ratio here in New Mexico and I didn't know if that was a primary one they use in Texas.

A That -- for waterflooding projects, whether it's unitized or cooperative, I myself, in all of the projects I worked on, used an expectation of 1-to-1 secondary to primary ratio and that that yardstick is used to measure generally the success of your secondary operation. I think that if anyone, given not only today's state of knowledge, but the knowledge that existed in the 1960's with respect to Spraberry, assessed secondary recovery prospects on a 1-to-1 basis, he would probably be committed pretty soon. That -- it would be in the Looney Tunes, it doesn't exist, and nobody, and a large number of projects, has been able to achieve that.

I've found, if I don't run on too long in response to your question, I don't intend to belabor it, in my analysis I only found one project that recovered through the end of 1987 more oil than the operator expected to recover when the project was initiated, and I was curious to know how that happened, because everybody else had gotten many multiples less than they expected, and I found that that operator didn't expect to get anything anyway, so everything was a surprise, and he's estimated his secondary ultimate recovery at 0.4 percent of primary, and with that kind of -- sort of unrealistic low thing, it wasn't too difficult to achieve more. But he's the only one that outdid his expectations but he did that by not expecting anything.

Q Are you familiar with the Austin Chalk?

A Yes.

Q Have there been any recovery efforts to date, to your knowledge, in that either waterflood or pressure maintenance in that trend area?

A Gosh, my experience with Austin Chalk goes back to the early 1950's and it had a reputation for primary even worse than Spraberry. It was a fractured, very tight, matrix rock, differing in that it was carbonate as opposed to sandstone and very treacherous. It would promise a lot but yield very little on the primary.

I don't know. The largest Austin Chalk development in recent years would have been in the Giddings

Austin Chalk play and that play was engaged in by a wide range of operators, both independent and major. Several thousand wells were drilled and due to a relatively new, to me, at least at that time, fracture definition from -- and what were called just bright spots on seismic work, and well treatment, completion and stimulation techniques, the operators were generally able to get substantially more primary recovery from that rock source than had been here-to-fore, but even with that success in terms of primary and enlarged development activity, I don't recall a single secondary recovery project that has been initiated in Austin Chalk, either gas injection or water, because of the fractures.

MR. LEMAY: Thank you, Mr. Powell.

Are there additional questions of the witness?

If not, he may be excused.

MR. DOUGLASS: That's our case.

MR. LEMAY: Thank you, Mr. Douglass.

Mr. Pearce, do you have direct witness?

MR. PEARCE: I do not, Mr.

Chairman.

MR. LEMAY: Mr. Lopez, anything from that side?

MR. LOPEZ: Nothing.

MR. LEMAY: Is Amoco still (not clearly understood), yeah. You don't have any witnesses for the Proponents?

MR. LUND: Not for the direct case.

MR. LEMAY: Fine. I think maybe if we could start with the opponents.

MR. KELLAHIN: Mr. Chairman, in the spirit of what you asked us to do, we have tried to keep track of the time consumed by each party. We find at this point the Proponents have utilized, exclusive of the Commission's time used in the hearing, approximately 8 hours of hearing thus far.

We believe that in cross examination we have used 2 hours and 45 minutes, approximately, of time in examining not only the Commission witnesses but the Proponents witnesses.

That's how we see the time thus far.

MR. LEMAY; Thank you, Mr. Kellahin.

Is there another timekeeper on the other side that might want to challenge that or is there pretty much agreement.

MR. DOUGLASS: We're still working on ours.

MR. KELLAHIN: Mr. Chairman, while we have a little break and moving things around, as I've told Mr. Pearce and Mr. Douglass, we have reprinted Mr. Lee's exhibit book that we passed out on Monday. There have been some changes.

One of the things we did is we numbered the pages so we can find the pages in the exhibit book and then as Dr. Lee can explain for us, he has made a recalculation on one of the pages that results in different -- different values demonstrated on that page.

If we might take a moment I'll have those copies which are available redistributed.

(Thereupon the noon recess was taken.)

MR. LEMAY: The hearing will resume.

Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Chairman.

MR. KELLAHIN: Mr. Chairman, we'd like to call at this time Dr. John Lee.

Mr. Chairman, we've circulated to the Proponents copies of Dr. Lee's exhibits. We have marked Dr. Lee's exhibits first of all, the ones that were distributed stapled, such as this, are Sun's Exhibit Number One. I have during the lunch hour bound some of those so the pages are easier to turn. This replaces what we passed out on Monday.

MR. LEMAY: Do we give this back to you?

MR. KELLAHIN: No, sir, you may have that.

WILLIAM JOHN LEE,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q Dr. Lee, were you sworn in as one of the witnesses on Monday of this week for this hearing?

A Yes, I was.

Q Dr. Lee, in the past have you been recognized by this Commission as an expert witness in the field of petroleum reservoir engineering?

A Yes, I have.

Q And did you testify on behalf of Benson-Montin-Greer, Sun Production and Exploration Company, in the Gavilan Mancos hearings held in March and April of 1987?

A Yes, I did.

Q And did you also testify before the Commission in the March, 1988, pressure maintenance hearing held in Case 9111?

A Yes.

Q Did you study of the Gavilan Mancos - West Puerto Mancos reservoir commence prior to the March, 1987 hearing?

A Only slightly before, yes.

Q And since that time have you continued to study that reservoir?

A Yes, I have.

Q Dr. Lee, have you been present throughout this week through all the testimony of the witnesses thus far in the case?

A Yes, I have.

MR. KELLAHIN: Mr. Chairman, I tender at this time Dr. John Lee as an expert petroleum engineer.

MR. LEMAY: Dr. Lee's qualifications are acceptable.

Q Included in your studies, Dr. Lee, did you study the alleged barrier in the Canada Ojitos Unit and its effect on pressure communication and fluid migration in the West Puerto Chiquito - Gavilan Pool?

A Yes, sir, I did.

Q When you and I discussed definitions and terms, what we referred to as the Gavilan Mancos Pool, are you referring to that area that's identified in the green outline on --

A Yes.

Q -- this display here?

A Yes.

Q And that is what the Commission defines as the Gavilan Mancos Pool?

A That's correct.

Q When we discuss the expansion area, do you agree as the others agree we're talking about the two rows of sections that start at the eastern boundary of Gavilan Mancos and move two rows of sections to the east?

A Yes, that's correct.

Q And is it your understanding, sir, that the area outlined in by the pink marker is the area contained within the West Puerto Chiquito Mancos Pool?

A Yes.

Q Dr. Lee, would you please explain to the Commission how you performed your study about the alleged barrier?

A Yes. My objective was to apply fairly simple material balance calculations to the pools and to try to avoid any complex mathematical computer model, but to be valid material balance calculations require that the area studied have reasonably uniform oil and gas saturations throughout the area and reasonably uniform pressures throughout the area, and, of course, that's not true for these pools as a whole, and therefore, I had to break the pools into five separate tanks, as I'll call them, in order to have areas in which I could satisfy the needs of applying material balance calculations.

Therefore my calculations aren't as simply as perhaps we would like but, still, they're by no means as complex as sophisticated reservoir simulators which model a lot of individual wells and try to capture a lot of detail.

It's sort of a -- sort of a middle ground that I've used to try to study this area.

Q Are these standard, well accepted, engineering calculations to explain observed reservoir facts?

A Yes. Material balance calculations are well accepted when the conditions for their applicability are satisfied.

Q You've indicated to us that you've taken into account the reservoir and divided it into 5 distinct tanks. Would you explain how you have -- how a material balance calculation like this is performed?

A Well, within each tank what I do is assume some amount of oil in place in that tank originally, and then I look at the production of oil and gas from that tank and with a given amount of production a certain pressure drop will result. The more oil and gas we take out the more the pressure will drop.

And I do this for all the tanks and I have to hook these tanks together because as pressure differences arise between different tanks fluid will flow from one tank to the other.

Well, I continue this process and after I've generated a number of pressures resulting from these production amounts of oil and gas, then I look at my calculated pressures and if I go back all the way to the start of the pool, I have observed pressures from these tanks that I can compare calculated pressures to. I do the very best I can to try to match these observed pressures. Perhaps the original assumption of oil in place within a tank was incorrect. I'll adjust that.

Perhaps the resistance to flow between different tanks also doesn't appear to lead to a good match of observed pressures, I'll adjust those until finally, I can get the best possible match between pressures observed historically and those calculated, using these tank-type material balance calculations with migration.

Q In linking these tanks you determined the oil resistance characterized by the affected permeability, the thickness products, needed to match the actual observed past performance?

A That's a good summary.

Q When we turn to page 2 of Sun Exhibit Number One, is that a display upon which you have placed the 5 tanks?

A Yes, it is.

Q If you'll give me a moment. As Exhibit Number One on page 2 you have a reduced copy of what has been handed out with this display?

A Yes, sir, that's correct.

MR. KELLAHIN: The Commission copies area little easier to read on the larger scale, Mr. Chairman.

Q On -- on the increased size display board on the easel here, Dr. Lee, does this also represent the same display we're seeing on Exhibit page 2?

A It displays the base map onto which I have placed the amounts of oil in place and the resistances of flow between the tanks, but basically this identifies the area and serves as the basis for subdivision into tanks.

Q Would you please explain the exhibit to the Commission?

A Yes. The major purpose of this exhibit is to simply orient you and show you what the final result of this trial and error process to identify the most probable oil in place that I could find and most probable flow resistance between tanks turns out to be that is that description which leads to the best match that I can obtain of observed calculated pressures in this reservoir.

And what we have found specifically is that with the division into five tanks, as I have here, the tank on the right is -- I will refer to that as the East Canada Ojitos tank.

Q That's this tank identified here, the eastern boundary of the West Puerto Chiquito Mancos Area and then it's divided further by this line?

A Yes, that's correct.

Q This is the area into which gas is injected for the pressure maintenance in the Canada Ojitos Unit. Why did you make that one tank?

A Well, because that tank is characterized by the fact that all the gas injection in the unit occurs there. The pressure within that tank is reasonably uniform. There are reasonably uniform fluid saturations in that tank because of the injection.

Q When we go to the next tank westward, is that the tank that's outlined by the next blue line within the center portion of the pressure maintenance project area?

A Yes, it is.

Q And as we move farther west, did you use as a tank the two rows of sections that represent the expansion area?

A Yes.

Q And then as we move into the Gavilan Mancos Pool, have you divided that pool into two additional tanks?

A Yes, I have.

Q And what was the reason to divide the pool into two tanks as you've done?

A Well, again basically a difference in pressures in the two areas. There was too much area and too much variation of pressure to consider that a single tank and therefore the subdivision into two on the basis of the most common pressures in the area.

Q Dr. Lee, do you believe your material balance calculations are accurate?

A Yes, I do. I believe they're reasonably accurate.

Q How well do the pressures observed historically in the area of these tanks match the pressures that you've calculated by this method?

A I think they agree reasonably well.

Q Have you prepared an exhibit that illustrates this comparison between calculated and observed pressures.

A Yes, I have.

Q And that is what is shown on page 3 of Sun Exhibit One?

A Yes. it is.

Q Would you please explain this exhibit to the Commission?

A What this exhibit is, is a verification or at least a comparison of calculated and measured pressures from this material balance work which I've been describing earlier

What we have here, what is on the vertical axis, is the pressure in each of the five tanks converted to a datum pressure at +370 feet above sea level.

On the horizontal axis we have the date

starting at the time at which production began from West Puerto Chiquito and extending through very recent history, through about March 1st of 1988, using the most recent data that we have available.

What we have on the graph, as I indicated earlier, is different lines, 5 different lines, which represent the calculated pressures in each of the 5 different tanks, and the symbols on this diagram represent observed pressures. Now the lines and the symbols are color coded to aid in the identification of which area's pressure calculations are shown in a certain color and the measured or observed pressures which correspond to that particular tank.

I think for purposes of orientation it might be simplest to look at the top line on this tank. This top line, you'll notice, is a green line and the color code says that's the calculated eastern Canada Ojitos Unit pressures. That's the injection area pressures.

And the symbol for the observed pressures in that area, we have a -- also a green cross.

The next calculated pressure line is in blue. That's at the central unit area and then the observed pressures are shown with a blue plus sign, and so forth for the other areas.

The lowest pressures that are shown here generally are the black line. That's the calculated pressures in the western end of Gavilan.

The lines are running together through much of history. They only begin to spread apart away from the unit area near the end of the historical period.

Q How would you characterize the agreement between the calculated and observed pressures?

A I think it's pretty good. It's certainly not perfect but considering the heterogeneity in this reservoir, considering some of the problems in pressure maintenance itself, I would say it's a pretty good agreement. I would say particularly so since about 1985, where I think we follow in some detail the general trends in the observed pressures in the field and this is important because it's during this time period in which the withdrawals have begun to accelerate and the pressures in the various areas of the field have really begun to spread apart and identify themselves.

Q Are the lines represented on the display actual well pressures or volume average pressures?

A The lines on the display are volume average pressures. That's pressure which I used to characterize that entire tank, which, of course, contains many sections, and therefore we shouldn't be surprised to have some variation of observed pressures within that tank, but our hope is to characterize that tank pretty adequately with this line.

Q Did you calculate the pressure differences between the project area, which means the Canada Ojitos Unit project exclusive of the expansion area, taking that on one side, and the pressure differential in the expansion area, do you -- do you calculate pressure differentials as large as those presented by Mallon in the March, 1988, pressure expansion case?

A Yeah, I think the magnitude of the pressure differences are comparable, some 3-to-400 psi pressure difference between the central part of the Canada Ojitos Unit as compared with observed between the unit and the expansion area as compared with, say, 400 or more psi observed pressure difference between the pressure maintenance area and the proposed expansion area.

A Mr. Hueni says that a barrier between the expansion area and the project area is required to explain those pressure differentials, is that correct?

Q No, I would propose that there is an alternate explanation simply by finding the flow resistances that I've found, which really constitutes a variation in permeabilities throughout the area; that is, some degree of heterogeneity. I certainly haven't captured all the detail with this 5-tank model, but at least with changes in permeability, and also I would say importantly, because of the very large amount of gas injection into this pool. In fact, an amount of gas injection so large that throughout much of history the pressure throughout the pool has actually been above the discovery pressure, which means more injection than total oil and gas production from the pool.

That large amount of injection plus this variation in permeabilities also explains these large observed pressure differences in the pool.

Q Is a barrier required or present in your reservoir description of the Mancos reservoir?

A No, it is not.

Q Mr. Hueni assumed a barrier would be required to account for the observed pressure differences, did he not?

A Yes, he did.

Q Is he presenting the kind of calculations you have?

A No. This is a different kind of calculation in which I tried to not only look at the immediate area around the alleged barrier, but tried to -- tried to look at the entire field and particularly take into account what's happening in the gas injection area.

Q When you look at the Gavilan Mancos Pool itself, and that's identified in the green area, within that area itself have you observed and calculated pressure differences within that area from the east side of Gavilan to the west side of 2-to-300 pounds differential?

A Yes. There are pressure differences of -- of that magnitude which are now observed between the east side and the west side. Let say 200 pounds difference over an average distance of, let's say, 3 miles.

Q During late 1987 within Gavilan itself what have you observed to be the range of pressure differentials during that period of time?

A During late 1987?

A Yes, sir.

Q The pressure differentials observed during late 1987 in Gavilan, again from the east to the west, have been on the order of 2-to-300 pounds actual measured pressures in wells.

Q What does that calculate to be a gradient in terms of pressure per mile within Gavilan?

A Well, across an average distance of 3 miles between the centers of these areas that would be a gradient on the order of 60 or 70 psi per mile.

Q Does it make sense to you as a reservoir engineer to say that there is in fact a barrier located between the expansion area and the project area and not a barrier within Gavilan itself?

A No, to me they're quite comparable; agreed the pressure differential and psi per mile is larger in the injection area but there's a huge amount of over-injection there, too. The gradient there might be on the order of 200 psi per mile.

In Gavilan, in which everyone agrees we have complete pressure communications, we have gradients on the order of 60 to 70 psi a mile, I would propose that these are reasonably comparable and there's no more reason to postulate a barrier in one area than there is in the other.

Q Dr. Lee, at this point I'd like to refer you to what has been marked as Sun Exhibit Two. Would you identify for the record what is Exhibit Number Two?

A Exhibit Number Two summarizes calculations and conclusions based on those calculations concerning migration across this alleged barrier, with this calculation being based on pressures observed between 6-30-1987 and 2-23-88.

Q Would you start at the top of page 1 of Exhibit Number Two, Dr. Lee, and describe the information contained on the display?

A Mr. Kellahin, if I might, I'd really like to refer first to the second page, which is a summary, and then come back to the first page and provide the detial on which the conclusion on the summary page is based.

Mr. Max Powell this morning pointed out to the Commission that the pressure in the Canada Ojitos pressure maintenance area had remained constant at about 1500 pounds from June 30th, 1987, through February, 1988, I believe, actually the dates that -- for which he provided the final pressure estimates were February 23rd, or so, but anyhow, generally, between the first of July and the first of March, he noted, and provided on exhibits information indicating that the pressure had remained constant.

Looking at what pressure might characterize that area as a whole, I would judge from his exhibit that the pressure on the average remained constant at about 1500 pounds per square inch with -- with some variation accordng to the pressure gradients that he drew on his exhibit this morning.

Q You're specifically referring to his Exhibit Forty-eight, Forty-nine and Fifty from this morning?

A Yes, sir, I am. Now, the implication of that important observation, Mr. Powell says, that whenever the pressure remains constant over some period of time, then we can make some important and revealing calculations about migration into or out of an area. We can do this very simply by noting that net migration has to be the difference between the injection of gas in that time period and the amount of production of oil and free gas during that same time period with each of these quantities expressed in reservoir barrels, because the pressure doesn't change, there's no expansion or shrinkage of the fluids remaining in that area, it's simply what goes in has -- less what comes out, the difference in those has to be what moved out through the process of migration.

So using that principle I made some calculations which I'll go into detail in just a moment, but I'd like to point out the point of these calculations and the conclusion that I reached from them.

Based on Mr. Powell's observation that pressure remained constant at 1500 pounds, I calculated that migration from the pressure maintenance area across this so-called barrier during this period from June 30th, '87, to February 29th, '88, was 624,000 reservoir barrels. The conclusion that I reach is that this barrier is not a seal. It's certainly not a barrier.

Now, how did I make the calculations. Well, I don't want to burden you with tedious detail but I think we at least need to look at the idea here.

I've identified on the front page some of the detailed information on which this calculation is based. I've noted from our production records on 6-30-87 and 2-29-88, which is really the date on which our production records are available, the cumulative oil production that we have on our records from this pressure maintenance area. I've also noted the cumulative gas production and the cumulative gas injection into the area, and of course the difference in these cumulative totals that we have in our records would be the incremental amounts of production and injection that occurred during this time period.

All right. So we've got amounts of production and injection to work with. The average pressure I found after careful study, I made a quick earlier calculation before the lunch break and in order to get it done just simply used without any correction Mr. Powell's data, but I have corrected that given time over the lunch hour to make a more detailed calculation. I've observed that the average pressure in the area based on the contours that he drew is about 1500 pounds.

Now, that's not really the pressure in the reservoir; that's pressure converted to a datum. That pressure to be converted to what it is on the reservoir in an average, has to be converted to what it would be at the average depth in the reservoir relative to that datum, and the pressure is 1500 pounds at datum. The mid-point of the project area is 1400 feet, so I subtract from 1400 feet the

370-foot datum, multiply by the gradient, the pounds per square inch per foot change in pressure as I go from datum into the area, and that gives me a pressure of approximately 1180 pounds per square inch.

We could -- we could argue a bit about what the gradient is and so forth, but I think that's a -- that's a reasonable estimate.

Now, to make the calculation I'm going to need some factors with which I can convert production volumes and injection volumes expressed at surface conditions into volumes at reservoir conditions, so-called formation volume factors, From tabulated fluid properties I could look these up. Now I'm ready to make my calculation.

Total production during this time period is equal to the surface oil rate times the oil volume factor, using the symbols QO and BO here, and the gas rate, this has to be free gas rate, not gas that was (unclear) in the oil but free gas, so I take the total gas produced, subtract from it the gas that was dissolved in the oil, and then convert that to reservoir conditions with a volume factor.

The result is I find that 743,000 reservoir barrels have been produced. That's oil plus free gas.

Next I take my injection and convert that to reservoir conditions and find that 1367-thousand reservoir barrels of gas have been injected during this time period.

The difference in these two numbers, I'll call it over-injection is 624,000 reservoir barrels. We've injected 624,000 more barrels into this reservoir than we've produced. Now the pressure stayed the same. If the pressure stayed the same, then a volume equal to the amount that we injected, had to leave that reservoir, and of course, the only place it can go is across this alleged barrier into the proposed expansion area.

So I conclude, based on these calculations that there's been net migration of 624,000 reservoir barrels.

Q When we turn back to your Exhibit Number One, and we're now on page 3, you have a display here of observed and calculated pressure measurements in these different areas of Gavilan and the unit.

A That's correct.

Q One of Mr. Hueni's exhibits, Proponents Exhibit Twenty, Mr. Hueni discussed with the Commission the fact that he found, based upon his analysis of the data, that the unit had a certain pressure at the time Gavilan was discovered and he displayed that by showing a dashed line on Exhibit Twenty and related that back to pressures taken in Gavilan. In doing so did Mr. Hueni take into conlideration the over-injection of gas that was taking place in the unit?

A No, they couldn't have with that line that he drew because as I've pointed out earlier, in fact, for a pretty long time during the life of the reservoir there had been more gas injected into the entire Gavilan plus West Puerto Chiquito reservoirs than there had been free gas and oil produced from those reservoirs and of course the reservoir pressure had to for some time period be above the original reservoir pressure level.

In addition, during this period in which over-injection was occurring the pressure throughout the pool as a whole, at least, had to be rising, and that character is totally missing from this graph.

Q When we look at your display on Exhibit Number Three and we get to the period about 1972, which on Mr. Hueni's display is right here, do you see that?

A Yes, sir.

Q When we get to that point on your display what happens to this line that Mr. Hueni has projected as a slowly declining line?

A Well, it's at exactly that point that the over-injection began. More gas began to be injected than there was free gas and oil produced from the reservoir and therefore the pressure in the overall pool had to increase in response to this more fluid coming in than going out.

Q And when we take into consideration the over-injection of gas what happens to Mr. Hueni's dashed line as we get to the point in time where Gavilan came into production?

A Well, according to my calculations that's about the general pressure level that we would observe in the West Puerto Chiquito at the time; in fact, most of the pressures in West Puerto Chiquito were actually even above that value.

Q When you get to the point where Mr. Douglass has put on this display 350 pounds pressure differential between Gavilan and the unit, what do your calculations show that pressure differential to approximate?

A It depends on what we talk about the unit, but basically there may be very little difference between the pressures in the area immediately adjacent to the expansion area and the pressures within the expansion area.

Q In your opinion as a reservoir engineer, Dr. Lee, is it reasonable to expect that the pressure differentials that you calculated are large enough to be an effective barrier between the two areas?

A There's no barrier between the areas.

Q In making your review of the observed

facts and doing the engineering calculations was it necessary for you to hypothesize a dual porosity reservoir to explain the observed performance of the field?

A No, it was not.

Q Why not?

A Well, basically we don't see the facts that support this hypothesis. We were able to match observed field pressures when we input observed production into these tanks, and in my opinion come up with quite a satisfactory match of observed performance.

In addition we are not at all convinced by the evidence saying that there is a dual porosity system in this reservoir. So we see no need to make that hypothesis.

Q Before we get to a discussion of the dual porosity issue, Dr. Lee, would you summarize for us then what your conclusions are based upon the material balance calculations insofar as determining a flow barrier between the expansion area and the project area?

A Well, briefly stated, I conclude that there is no flow barrier at the edge of the current pressure maintenance area in the Canada Ojitos Unit. The reason why is because observed pressure drops in the field in my judgement can be explained by permeability variations rather than an absolute permeability barrier.

Q And that's what you've shown us are your conclusions on page 4 of Exhibit One?

A Yes, sir, that's correct?

Q Did you project future performance of the pools with your material balance calculations?

A Yes, that was the next part of the study, to project future performance.

Q And what were those plans that you utilized future performance? Did you use one plan or did you have several different, alternative, operating plans for the field?

A Look at two major possibilities. One was to continue operating the field just as it is currently. The second is to change to a pressure project. I made the judgment that if the operators really wanted to do this they could have a pressure maintenance project starting by August of 1989. That's a subjective judgement, but in any event, it will at least serve to compare under something that's conceivable what the performance of the reservoir might be with and without a pressure maintenance project.

Now, for the pressure maintenance project there's still a question to be answered and that is what should be done with the oil, and particularly gas, withdrawals in the interim period between the time the project -- between now, or let's say July 1st, and the time such a project could begin?

To answer this question I looked at three more possibilities, and that is, in the interim period, continuing to produce the field under the current allowable of 800 barrels per day for 640 acres with a penalty gas/oil ratio of 600 cubic feet per barrel or a gas limit of 480 MCF per day of gas.

The second alternative that I looked at was to produce the field at reduced gas allowable thinking that if we cut gas production back even further, this would conserve reservoir energy and might lead to at least a slightly more successful improved recovery process.

So the second alternative I looked at was the same current oil allowable but a gas allowable reduced to something approximating current solution gas/oil ratio in the pool, which is about 235 standard cubic feet per stock tank barrel and that amounts to about 188 MCF per day of gas production.

The third alternative that I looked at was to see what would happen if we increased the allowables to those used in the high test rate period, the allowables being 1280 barrels of oil per day with a penalty gas/oil ratio of 2000-to-1 or 2560 MCF per day of gas for a well on 640-acre spacing.

Q In one of the plans we're talking about pressure maintenance in the Gavilan Mancos Pool itself.

A That's correct.

Q And you're assuming that within Gavilan Mancos itself under your analysis, that we're starting pressure maintenance as of August 1st, 1989.

A That's correct. One more item that I need to add, and that is I felt that to -- to study this in a way that would -- would minimize the confusion, that we would assume that a boundary protection plan could be created between Gavilan and the Canada Ojitos Unit. In fact, Mr. Greer, being he feels that a reasonably effective plan is already in place, and probably became pretty active around the first of 1987, so in these projection runs what I did, unlike my match of past history, is simply close off any communication between Gavilan and Canada Ojitos, and from January 1st, 1987, simply projected performance as if these were two entirely different pools with no migration either way.

Q When you're talking about Canada Ojitos, you're talking about the main project area including the expansion area.

A That's correct.

Q The boundary protection plan that Mr. Greer says in place is the one between Gavilan and West Puerto Chiquito.

A That's correct.

Q And that's the assumption you made, that's what you (unclear)?

A Yes, sir.

Q All right. We've got one analysis of Gavilan under pressure maintenance and you had another analysis without pressure maintenance.

A That's correct.

Q All right. What did you conclude with this phase of your study?

A My conclusions were that recovery can be increased and I believe that the calculations are at least (unclear), the recovery can be increased and can be increased to the maximum the less oil and gas we take out of the ground prior to the pressure maintenance project, and then following that minimum withdrawal period by a pressure maintenance gas injection project.

Q Let me direct your attention, Dr. Lee, to page 5 of Exhibit One, now, and have you show us the calculations and the support by which you reached that conclusions.

A All right. First, I want to make a comment about page 5. In an earlier copy of the exhibits that we handed out to particularly the counsel for the Proponents the numbers were significantly different, and the reason that they were different was because we completely messed up our calculations. They were just plain wrong.

In trying to put in the barrier between West Puerto Chiquito and Gavilan we ended up putting it right in the middle of Gavilan and so we had part of Gavilan with absolutely no pressure maintenance and West Puerto Chiquito plus the other half of Gavilan. So the numbers were completely wrong. I apologize but these new numbers do have this boundary protection plan in the correct place.

Q And that's what's represented on Exhibit Number Five?

A Yes, that's correct.

Q Now, sir, lead us through what this exhibit shows?

A What this exhibit shows, it really addresses the two different kinds of issues that I raised earlier.

First, what is the effect of pressure maintenance, and second, for a pressure maintenance project what will be the effect of different allowable schemes prior to implementation of the pressure maintenance project?

Now, first question, what's the effect of pressure maintenance?

To answer that question we simply projected the model forward to an economic limit of 400 barrels of oil per day total production from both pools and when it reached that limit we said we had our ultimate recovery, and with continued current allowables we projected an ultimate recovery of 5439 thousand stock tank barrels.

Now the important point is that based on these tank type material balance calculations we projected ultimate recovery of 10 -- about 10.2 million stock tank barrels. That number constitutes about 22.6 percent of the oil in place in Gavilan. The number without the pressure major project constitutes about 12 percent of the oil in place.

As a check on those numbers I compared with numbers that Mr. Hueni projected with his model and presented at the March, 1987, hearing. He had a slightly different oil in place but he projected with a low pressure gas injection -- low pressure gas injection project to enhance recovery that about 20.1 percent of original oil in place could be recovered compared to my 22.6 percent.

I think the numbers are comparable and sort of serve as a check on each other, even though the type of reservoir model assumed was significantly different.

Q Within Gavilan under pressure maintenance you have found that that improves recovery?

A Yes, at least according to this -- the calculation process. What this says is there appears to be nothing in incentive; that we really need to study this question carefully and try to really quantify what that reserve is with a more sophisticated type reservoir analysis. This says directionally there may be incentive there.

Q What's the effect on the analysis if the allowable rates, or the rates of withdrawals in the Gavilan Mancos are restricted or what we have characterized as the lower rates versus the high rate?

A Well, basically, and this information summarizes the bottom half of this exhibit, basically, the lower the rate, particularly to the gas withdrawal rate, between now and the time of the implementation of a pressure maintenance project, the greater the ultimate recovery for that project; about 11-million barrels according to this calculation would be possible if we cut the gas back to the current solution gas/oil ratio; about 10-million barrels ultimate recovery if we maintain our current allowables; and about 7-1/2 million barrels recovery if we increase the allowables to the values that we had during the high test rate period in the field.

Q Dr. Lee, did you try to find the optimum pressure maintenance project operating plan?

A Oh, no, I'm not -- not proposing that this is it at all. I'm simply saying that this is -- this is a feasibility study, operating the pool under a consistent set of rules that I think would give us an indication of what the potential might be.

Q Are additional recoveries due to pressure maintenance injection possibly greater than you calculated?

A Could be; could be less.

Q Turning to page 6, Dr. Lee, have you set forth in writing, then, your major conclusion with regards to the future performance projections?

A Well, my conclusion is simply that ultimate recovery in Gavilan can be increased by minimizing oil and gas withdrawals now, conserving reservoir for additional recovery with pressure maintenance later.

Q What are your recommendations, Dr. Lee?

A My recommendations are, basically, one, maintain the West Puerto Chiquito - Gavilan boundary at its current position, given, I think, particularly the conclusive evidence of migration during a recent 6-month period; there's no reason to move that boundary.

The expansion area and the current pressure maintenance project area are in clear communication.

The second recommendation is to maintain the lowest oil rates, the minimum gas production possible.

Q These are shown on page 7 of your exhibit?

A Yes, These recommendations are on page 7 in the book. I would recommend the lowest rate possible or desirable now from a reservoir standpoint because they can conserve reservoir energy and can lead to improved recovery if a pressure maintenance project is installed in Gavilan.

And then the third recommendation is sort of a truism, but I still feel that I need to say it, and that is that Gavilan operators really should be encouraged to study and following that study, if they identify economic viability, putting in the pressure maintenance project to improve recovery from the reservoir.

Q Dr. Lee, I'd like to go to a different subject at this time. I'd like to address the issue of migration between Gavilan and the West Puerto Chiquito Mancos Pool.

Did you hear Mr. Hueni earlier this week testify that migration has been going from the Gavilan Pool into the expansion area and the West Puerto Chiquito Mancos Pool?

A Yes, I did.

Q And have you made a study of that allegation?

A Yes, I have.

Q And what do you find?

A I found that, in fact, there's been net migration into Gavilan from West Puerto Chiquito.

Q Describe for us how you reached that conclusion.

A Well, basically, using the same simplified material balance tank type models that I've used for the earlier parts of this study.

Q Have you made an estimate for the Mancos Pool, the Gavilan Mancos Pool Area, from the beginning of production to January 1st, 1987?

A Yes, I have.

Q Have you prepared an exhibit that demonstrates the results of this part of your study?

A Yes, I have. It's found starting at page 9, but really the part that I want to get to is on page 10 of the exhibit booklet, and I apologize for skipping pages but this was prepared as rebuttal testimony but I think since we've -- since I'm combining my rebuttal and direct testimony, I'm going to jump to this rebuttal section of the booklet now.

On page 10 I think we can see a graphical summary of the calculations that I've made.

Q Let me have you first of all explain the exhibit to us and then let's talk about the conclusions.

A All right. What this exhibit is, is a graphical representation of historical migration into the proposed pressure maintenance expansion area from Gavilan, and to do this we have shown on the vertical axis of this exhibit the cumulative migration in thousands of stock tank barrels and that's migration to the expansion area. In other words, a positive number means that there has been migration to Gavilan; alternatively, a negative number -- I think I said that wrong.

A positive number means net migration to the expansion area and a negative number means negative migration away from the expansion area to Gavilan.

That cumulative migration, of course, is shown as a function of time up to January 1st, 1987.

Q What does it show you between the Gavilan and the West Puerto Chiquito Mancos Pools from the period of 1963 to 1972?

A Well, during the period from 1963 to 1972, you'll notice that we have positive cumulative migration. This means that migration is coming from Gavilan into the proposed expansion area, and then at that point the direction of migration changes. Now remember what we have plotted here is cumulative migration.

So the rate was not necessarily increasing but the amount of migration was accumulating, reached a maximum about 1972.

At that point the direction of migration turned around. We had at that point migration going away from the expansion area and back toward Gavilan. It crossed zero again in the late seventies, say, and particularly in the recent time period, according to these calculations, there has been an increasing amount of migration from the proposed expansion area to Gavilan. Mr. Greer feels that he has a plan in effect now which should do a pretty good job of stopping oil migration but I think the calculations, although they can't be taken literally in the sense of quantifying with any precision the amount of migration, I think, at least do show the direction of migration, and leave us, in my judgment, with net migration from the expansion area to Gavilan.

Q All right. So I understand the display on page 10, if you get to the zero line on the vertical axis, if you simply put a sheet of paper through the zero line horizontally on the display, you can see that above that horizontal line the line will show migration from Gavilan into West Puerto Chiquito?

A That's correct.

Q And then if we reverse the process and put the page above the zero line on the display, there's a certain portion on the horizontal date scale in which the line is obviously evident.

A That's correct.

Q And when that occurs, then, we see migration from West Puerto Chiquito Mancos into Gavilan.

A On a cumulative basis there has been net migration to Gavilan at that point.

Q Would migration from West Puerto Chiquito Mancos to Gavilan be even greater if oil and gas rates were increased in Gavilan?

A Well, at least protection of the boundary would become more difficult.

Q What is the basic cause of the past migration, Dr. Lee?

A The basic cause of past migration, first when we had migration coming from Gavilan into West Puerto Chiquito, that came because of withdrawals from the West Puerto Chiquito before we had substantial over-injection, but I think the predominant force that began in the -- in the early 1970's is because of the over-injection in West Puerto Chiquito before Gavilan had been developed. We were simply pushing fluids into Gavilan, simply compressing the fluids that were there because of this over-injection in Canada Ojitos.

As there was more and more over-injec

tion the pressure difference built up. Gavilan was finally developed, oh, first well in about 1982, but really significant production began in 1984 and 1985 and that's the period in which substantial pressure difference developed. Now Mr. Greer is implementing his boundary protection plan, minimizing the pressure gradients. Looking at displays of pressures on the other exhibits, I'd say, you know, you can look at some wells and say the pressure gradient is one way and others say the pressure gradient is the other way. I'll say that at this point we've probably substantially halted cumulative of oil migration.

Q Would you turn to page 11, Dr. Lee, and identify and describe that display?

A This display is really just for information and I'm not going to base any important conclusions on it at this point, but this next page simply is the same sort of plot except this is historical migration into the proposed pressure maintenance expansion area from the current pressure maintenance -- from the current pressure maintenance area, the kind of migration that we talked about earlier today that can be deduced from Mr. Powell's exhibits, in which case we inject more than we produce, the pressure remains the same, and we have migration. That's -- that's the sort of thing that this displays, and it shows increasing amounts of that migration in recent times with increasing pressure gradients.

Q As we turn to page 12, then, would you identify and describe the display on page 12?

A Page 12 simply puts together in one graph the migration on a cumulative basis from the current pressure maintenance area into the proposed expansion area the cumulative migration into the proposed pressure maintenance expansion area from Gavilan.

Q Dr. Lee, have you prepared as rebuttal testimony exhibits and discussions dealing with the dual porosity reservoir hypothesis?

A Yes, I have.

Q Would you like to present that now?

A Yes. I'd really like to start with a response to Mr. Elkins' comments yesterday. I think this is an appropriate place to make those comments.

Q Let's refresh everyone's recollection. Yesterday Mr. Elkins described his calculations and assumptions and said that there were portions of your prior work in March of '87 with which he agreed and there were other portions of your calculations with which he disagreed.

Could you refresh our recollection and explain to non-engineers in clear English for us what is in fact the areas of which you have agreement, those areas of disagreement, and whether or not that disagreement is significant to us?

A Yes, I will. I think basically we agree on most things.

Where we disagree is in an assumption about the reservoir description, a perception, and I'll get to that in just a moment, but let me start with agreement.

Mr. Elkins noted particularly that he felt that using the EI function, as Mr. Greer has been doing, to analyze interference tests, is a valid technique for characterizing the permeability thickness of product in a reservoir. This has been a subject of contention in several hearings here and really it was heartening to have the endorsement of that method which Mr. Greer, with my encouragement, has been using for some time.

So we agree on the fact that we can get permeability thickness product from a properly run interference test, and the analysis that he cited he said directionally agreed with the results that Mr. Greer and I got.

Now, Mr. Elkins at this point said that he had a disagreement with me because a thorough analysis would, as far as an interference test analysis also calculate a porosity thickness, compressibility product, and if we knew compressibility we might be able to get porosity thickness of the fracture system.

Well, I'd like to point out that I really agree totally with that recommendation. When I analyze an interference test I always calculate porosity thickness, as well as permeability thickness, and in fact, the basis for the porosity thickness product that we have used throughout this study is based on analysis of these interference tests, but it's based on an analysis of all the interference tests that we can look at and our perception is that the porosity thickness product or -- and given an estimate of thickness a porosity of about .27 percent, which we use in many of modeling studies and so forth that we do, the source of that number is interference test analysis.

Now, the particular test that Mr. Elkins chose to analyze in which he got a rather different result than the number that we use here, was a test that we feel has some subtle problems, problems of a gas saturation near one of the wells in the testing procedure.

Mr. Greer ran that test and he's going to talk about that problem and the reason why he doesn't give as much weight to that particular calculation as he does to the bulk of the interference tests that he's run in that one.

But my point is that I agree completely with Mr. Elkins. We should also make a second calculation and I will assure him that I do.

The, I think, more significant error -- area of apparent disagreement arises over the role of a matrix in this particular reservoir. I think this goes right to the heart of the issues that we're addressing here in this hearing.

One thing that Mr. Elkins did was make a calculation using the extremely small permeability number that I had calculated after correcting core permeabilities to in situ conditions and Mr. Elkins pointed out that even with that extremely low permeability, if you have small matrix blocks, you can still produce a significant fraction of the oil from that block as long as it's small enough, I believe he used a number of, say, 2 feet. I think herein lies the problem. My perception, and this is based on very detailed studies by Mr. Greer, my perception is that the size of the blocks surrounded by the major large fractures n this reservoir is not on the order of 2 feet but on the order of several acres to tens of acres, and I believe that any smaller spacing is -- is (not clearly understood.)

Now again, Mr. Greer will dig into this issue in detail and will present to you in his testimony later today or tomorrow the details of this study that he's made based largely on observed performance.

But I think that's really a disagreement in perception. Mr. Elkins has perceived small fracture spacing, I have perceived large fracture spacing. I think we would both agree that with extremely low permeability with large fracture blocks we couldn't get much of that oil out; with small fracture blocks I think could agree that we could get that oil out.

So it's really a difference in perception.

I think as a final point, though, I would note that part of the reason for my perception is based on the examination by our geologist, Mr. Dick Ellis, of the core from the Mallon Davis Federal 315 Well.

Q Let's turn to Exhibit page 13 --

A Well, let me -- let me first talk about the visual examination.

Q When we get to page 13 that will show the core data for this core that you're about to discuss.

Right. Yeah, first I want to talk about the qualitative observation, and that observation was that there was no oil bleeding from that core, it was completely clean of oil. There was some observed residual oil saturation at certain points but my major point is that my observation was that here's this core of matrix. Now that core of matrix is brought out to atmospheric conditions.

Look at the Delta P's that's possible now with that core coming from the reservoir and facing atmospheric pressure outside. What a fracture; to have the complete world around that core at very low pressure, and there was no oil bleeding, no sign of oil bleeding from that core.

Now based on, really, a lot on that perception of the core we concluded that whatever the permeability of that core is, it's simply not going to bleed oil to a fracture if it won't bleed oil even to the world at atmospheric pressure.

You did refer me to page 13. Page 13 deals now more quantitatively with my thoughts on the meaning of the core data. I observe on page 13 that the average permeability from that core is less than .0164 millidarcies. Now, why .0164 and why less than that?

The laboratory analysis of permeability for that core are tabulated on page 14 and those tabulations are graphed on page 15 so we can kind of get a visual image of what the situation is.

The geometric mean of these tabulated permeability numbers is .0164 millidarcies but that's misleading, because 31 of those 51 samples have permeabilities less than .01 millidarcies even though they're entered as .01 here because that's the lowest permeability that this laboratory could make. So the mean that we get is a lower

-- is an upper limit to the average permeability from this core.

The figure may give you better insight into that. You'll notice all these permeabilities level there as .01 millidarcy value.

Well, if we take that upper limit permeability and correct it to (unclear) conditions we get the low permeability that Mr. Elkins talked about yesterday that I had used previous, .00006, or so, millidarcy.

I think it's important to observe that that cored well was a dry hole. That matrix is not productive.

But I've gone a little bit further than that; made some simulator calculations and I know you don't want to hear a whole lot about the simulator calculations, but, you know, Mr. Weiss expressed the need the other day to be able to quantify what a rock with a (unclear) permeability would do. Well, I don't know of any way other than this to do it. I won't bore you with a lot of details but I will observe that we took this permeability, put it into a simulator and observed that only -- well, really less than 1 percent of the oil in place in that matrix with that upper limit permeability could be produced by fractures and I will note here that in this analysis we assumed a large fracture block.

So this -- this result is necessarily based on the perception that the fracture blocks are large. Specifically the simulation had a fracture block of dimensions 270 feet between fractures; that's what it simulated.

On page 16 I've compared simulations that I did using this permeability and simulations that I also did using the properties reported by Mr. Hueni in his testimony last March.

I don't want to burden you with a lot of detail but I think a fairly complete summary is there. The important thing is that there are really three basic differences between the properties that Mr. Hueni used last March and the properties that I used this time.

The most important one is probably the permeability. I've used a much lower permeability based on my perception of the capability of this core.

The second difference is a difference in the gas and oil relative permeability curves. Actually Mr. Hueni used curves which are more favorable to the flow of -- or let's say less favorable to the flow of oil than I did, so I really was more charitable towards the oil but I did use curves which I think, particularly for the matrix, are -- are more characteristic, more likely representative.

The third difference is an important one, and that is in Mr. Hueni's modeling work he assumed what we call pseudo-steady state, whereas I assumed what we call unsteady state. Now what do those words mean? Well, pseudo-steady state assumes that the pressure distribution is established throughout the matrix instantaneously and that we can characterize flow from that matrix simply by a difference of a pressure in the matrix and a pressure in the fracture.

In the unsteady state assumption, which I believe to be more representative, what we do is let the pressure distribution go into the reservoir and the pressure drawdown move into that matrix in increasing amounts with time.

So that assumption, the permeability assumptions are really the major ones; using my numbers I would estimate less than 1 percent of the oil in place recovered; using Mr. Hueni's numbers I would estimate more than 10 times that amount would be recovered.

So difference in assumptions leads to difference in calculated results.

Q Let's go to page 16 of this exhibit, Dr. Lee. What have you put on this page of the exhibit?

A On page 16 I've simply summarized those characteristics which I think are needed to understand the details of the characteristics that I've just described.

Q Were cores from any other wells in the field analyzed?

A To my knowledge there were a couple of others for which results have at least been released. There may be others cored and analyzed but I'm not aware of them and I do not have access to the records.

The other two wells that I'm aware of are the Mobil Lindrith B-38 and the Mallon Howard Federal 1-11. In summary, both of these wells also have low permeabilities which become even lower when corrected to in situ conditions, so I don't see any reason to change the opinion that matrix permeability is pretty low.

Q Have you prepared an exhibit which summarizes field operations which help you evaluate the dual porosity hypothesis?

A Yes, I have.

Q That's on page -- well, let's identify these next displays, Exhibit 16A and 16B.

A 16A and 16B are backup detail for the simulation of production from a dual porosity reservoir using a set of assumptions which I think are at least reasonably close to those that Mr. Hueni has endorsed and a set of assumptions that I believe are representative.

Q Let's go on to the dual porosity reservoir hypothesis and look at the field observations then.

A All right, sir.

Q On page 17 of the exhibit what have you shown here?

A Page 17 I've sort of summarized some information that's presented in detail on the following pages.

Here's -- here's what the message is in summary. Eight wells in a 6-section area of Gavilan, eight wells which are amid some of the best wells in the field, are nearing depletion and despite the low pressure in the fractures in the area of these particular wells, it's about 1000 pounds now lower than the original pressure in the system. These wells are declining rapidly and are nearing abandonment conditions and they're doing so because of declining capacity. It doesn't have anything to do with oil allowables. Their capacity is on a steep decline.

The point is that they're now 1000 pounds, or more, below discovery pressure and the matrix is not doing a thing to support production in these wells. Now if the matrix can't do anything with a 1000 pound draw-down below discovery, is it ever? I would conclude that it's not. It's just not contributing now, in my judgment it's not going to contribute.

Page 18 --

Q That will show us the specific area in the Gavilan Mancos Pool in which you have found the 8 wells in this 6-section area?

A Yes, page 18 does show the specific area in which we found these 8 wells.

Q Let's look, so that we all know what the 8 wells were, what portion of Gavilan are we dealing in now?

The 8-section -- the 6-section area is in 28, 27, 33, 34, and down in 3 and 4.

A Yes, that's right.

Q Is it this portion of the reservoir.

A That's correct. We've outlined this portion of the reservoir with a broad pen. The 8 poorer wells that I was describing to you are shown here, they're identified in circles.

The 4 higher quality wells, obviously in the same general vicinity here, are identified with rectangles around the well name. These are the 8 wells in question.

Q Let me direct your attention, Dr. Lee, to the issue of the significance of the shape of the build-up test plots that Mr. Weiss was discussing with us on Monday. Mr. Weiss stated -- Mr. Weiss stated that the shape of the build-up test plots for the Mobil Lindrith B-37 Well was evidence of dual porosity characteristics in the Gavilan Pool. Do you remember his discussion on that issue?

A Yes, sir, I do.

Q Do you have an opinion on this interpretation?

A Well, my opinion is that there is another possibility, an alternative explanation and one in fact is within the evidence I consider to be more probable.

Q Let's turn to -- first of all, before we get there would you simply identify for us the information contained on exhibits, pages 19, 20 and 21?

A Yes. On page 19 I show the oil capacity of the 8 wells that I mentioned earlier and also their gas/oil ratio. Average capacity in barrels of oil per day per well has declined from, oh, 250 barrels per day, pretty good wells, down to less than 20 barrels of oil per day continuously.

The production data which provided the statistics that back up this graph are shown on pages 20 and 21.

Q All right, sir, when we turn to page 22 let's have you discuss with us the dual porosity reservoir hypothesis and the inferences that are drawn from the pressure build-up test plot shape.

A All right, the shape of the pressure build-up test plot from the mid- , really late would be a more accurate modifier, 1987 test of the Mobil Lindrith B-37 well is indeed similar to the shapes that characterize build-up test plots from dual porosity reservoirs, as Mr. Weiss has very correctly observed.

Q Do you see a a pressure build-up test plot on the other Gavilan Mancos wells in this test area that have a similar shape?

A This was the only one that Mr. Weiss identified and I've looked hard, too. I think they're few and far between.

Q Do you have any other explanations for the shape of this plot other than a dual porosity hypothesis?

A I think there's another very logical explanation. There are other phenomena and the one that I believe is responsible for the shape of this curve is called phase redistribution in the wellbore. Basically what this is is that when we shut in a well for a build-up test, liquid in the wellbore will drop to the bottom of the wellbore and gas that's in that wellbore may rise to the top. Under certain circumstances that phase redistribution can lead to the same shape that was observed in the build-up test in the Lindrith B-37 Well.

Now, why do I believe that's a more probable interpretation for this well? Well, because I have clear evidence in this field that phase redistribution is occurring. Extreme cases of phase redistribution, when it's really severe, result in what we call a pressure hump and that pressure hump has virtually no other cause. Pressure humps are present in several test plots and probably to understand what these ideas mean and what this curve shape is all about we need to look at some graphs which are in this section of the booklet. I think we can start with page 26.

Page 26 is the November, 1987, build-up test plot from the Mobil Lindrith B-37 Well. This is the Horner Semilog Plot that Dr. Kohlhaas referred to this morning, the most common way of analyzing data from build-up. What's plotted here is pressure measured downhole during a shut-in period on the well, and on the horizontal axis we've plotted what we call Horner time, or Horner time ratio, a way of plotting data suggested by Mr. Horner, that you've heard described earlier today.

With this particular plot that I have here the time since shut-in is increasing from right to left for this particular time ratio, so earliest time data on the far right, the final data in the build-up test are on the far left, and of course those final data are at the highest pressures.

Now, this -- this curve does have some

of the shape characteristics of a dual porosity reservoir. The early times on the right with the steep slope and then the slope changes and there's a little hump in this but after that hump the pressures sort of level out like they are going to build-up completely.

In a dual porosity reservoir, what that leveling out means is the pressure's built-up completely in the fractures and the matrix hasn't had a chance yet to begin to have its influence, but when the pressure tries to level out in the fractures, then there's a kick up from the matrix, which is at higher pressures and it feeds fluid into the fractures until pressure takes off back up again and it can continue up for a long time.

Well, there's some of this rise, leveling out and then kick back up in this test and this is what led Mr. Weiss to the conclusion that here might well be dual porosity pay.

Well, as I noted, another phenomena that leads to that same shape curve is phase redistribution, liquids dropping down in the wellbore after shut-in and to give clear evidence that that's going on in the field, I'd like to look at the plot on page 27.

That's another Horner graph of build-up test data. This is a plot of data from Sun's High Adventure No. 1 of a June, 1987, build-up test.

Q Let's find the well on the exhibit. Here's the High Adventure Well here in Section 8?

A Yes, sir.

Now, what happens here is a steep build-up at early times and a pressure rising to a maximum and then dropping down below that maximum pressure.

In extreme cases where a phase is redistributing you can get a high pressure gas column above an oil column which has dropped down below and the pressure in the wellbore can actually rise above the pressure in the formation and it could start pushing oil back in the formation and it will continue to push until the pressure in the well is less than the pressure in the formation and then the pressure will start building back up again.

Well, here, I think, is clear evidence of that occurring in this field and there are other examples of this.

Now what does that have to do with the Lindrith B-37? Well, my judgement is the Lindrith B-37 is a less severe example of it. If we refer back to page 26, there's a little hump there. I don't know if the pressure, that particular pressure reading is any good, but I think you can identify on that curve a point where the pressure reached a maximum and dropped back down.

But that's not really the essential

point. The essential point is that when phase segregation is not severe enough to cause a hump, it can still cause this shape curve.

If you will refer with me back to page 23 of the booklet, I'd like to give you some documentation for that assertion.

Page 23 is the title page of a paper written for the Society of Petroleum Engineers by a graduate student of mine and me. The title doesn't appear to have anything to do with the issue that's in question here but in fact we studied as one of the considerations in this paper the problem of the effect of phase redistribution on build-up curve shapes.

I haven't given the complete paper here because I don't think it's all that necessary. I think this can serve to identify for anyone who would like to read the complete contents. I've given some figures on page 24.

What I'd like to focus on now is simply conclusion number 4 in this paper, which is found on page 25, and I have it completely underlined. What it says is this: "When the distortion caused by phase redistribution is not severe enough to cause a hump," like we saw in our second example well, "the characteristic shape of the pressure [buildup] behavior could be misinterpreted as that from a dual porosity reservoir. The composite reservoir behavior could also be misinterpreted as an effect caused by the reservoir drainage boundary." Phase redistribution could make a test look like there was a boundary there. "When such a characteristic shape is displayed in a transient test, more information should be sought about the reservoir geology, reservoir fluid phase behavior and fluid properties before a model -- ". That is, a basis for interpretation, an idealization of what that reservoir and well are like before you choose that model.

Q Would you turn to page 28, Dr. Lee, and summarize for us your conclusions about the dual porosity reservoir hypothesis?

A Well, in summary on page 28 my conclusions are first that available core data indicates the matrix permeability is extremely low.

The second conclusion is that reservoir simulation using available core data indicates that the matrix will not contribute significantly to pool reserves.

Now, again, that's subject to my perception that the size of the fracture block is large.

The third conclusion is that actual field performance in an area of the field indicates that there is just no significant support from the matrix in that area in a number of declining wells that were good wells a short time ago.

And the fourth conclusion is that the build-up curve shape on the Mobil Lindrith B-37 does not prove dual porosity behavior. In my opinion phase redistribution in the wellbore is a more likely explanation.

Q When you look at phase redistribution, Dr. Lee, when you see this pressure hump on this curve, is there any other explanation for that effect?

A That's the most common. There can always be things like leaks and so forth, but that -- that hump is, you know, given non-mechanical problems, it's going to be caused by phase redistribution and when you see it a number of times you increase your certainty in a given field that that's a problem; the problem particularly is getting higher and higher gas/oil ratio production, which again we have in this field.

So I think it's the most probable explanation.

MR. KELLAHIN: Mr. Chairman, that concludes my direct examination of Dr. Lee.

We'd move the introduction of Sun Exhibits One and Two will be admitted into the record. Thank you, Mr. Kellahin.

Mr. Carr, do you have any --

MR. CARR: No, I do not.

MR. LEMAY: -- questions of Dr. Lee?

Let's take a fifteen minute break and be back at 10 minutes to 3:00.

(Thereupon a recess was taken.)

MR. LEMAY: Mr. Kellahin, I guess you're through with direct.

MR. KELLAHIN: Yes, sir.

MR. LEMAY: And Mr. Carr does-not want any. Mr. Douglass you may cross examine.

MR. DOUGLASS: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. DOUGLASS:

Q Dr. Lee, I believe you indicated that on the dual porosity matter that one of the factors that was very important to you was the report that you had from Mr. Dick Ellis, who was there when the core was taken and that there was no bleeding oil from the core. Is that correct?

A Not there when the core was taken but an observer of that core. Yes, he observed that. He's also looked at micro-photographs, and so forth.

Q Well, I wanted to see if I understood, in other words he actually observed the core when they laid it out on the rig floor and saw that there was no -- no oil coming out, no bleeding?

A I'm not aware of him being there when they took it out and laid it on the rig floor.

Q Well, when you said there was no bleeding oil out of the core, what did you mean by that?

A Well, when he observed the core there was simply -- simply no oil on the surface. I really don't know any more than that.

Q Okay. You don't know when he observed it.

A No, I don't.

Q Well, let's assume that he observed it right when it came out and saw it immediately when it came out of the core barrel and there was no oil bleeding out of the core. Let's assume that, and let's assume, also, that you took a pressure core at the same time. Now, a pressure core is one that you actually core and you take out under pressure where you don't have the wellbore effect when you take out a conventional core, is that correct?

A That's correct.

Q And let's suppose that you were given the parameters in that pressure core and through the calculations, obviously, that you're very aware of, that you knew that there had to be oil coming out of that core that had been brought up out of the -- out of the well that Mr. Ellis observed, but you have this physical observation where there's no oil coming out of the core.

Under those circumstances would you question your calculations as to whether the data that you'd been given was correct as opposed to the actual observed information that Mr. Ellis had seen?

A That's --

Q Without looking at it?

A That's a pretty complicated question, you know. Even if we -- even if we say he did observe oil coming out of the core, we still have what I think is the larger issue of what is the -- what is the size of the fault block.

But back to the core itself, you know, my experience is that the poorer the rock the more likely it is to bleed and when it doesn't bleed at all, you really have a problem.

Q Well, my real question was wouldn't tend to believe Mr. Ellis more than you would your calculations if he'd actually seen that there wasn't any oil coming out of that core?

In other words, that would be an observed fact, wouldn't it?

A Yes, sir.

Q Now, the -- let us refer to page 3, if we could of your report here.

Let's see if I observe -- see if I understand this. This calculation came from a reservoir model, in fact, I assume 5 separate models, 5 tank calculations, is that correct?

A 5 tanks together in one model of the reservoir.

Q 5 tanks, and those tanks you've already gone over on the exhibit here that you've -- the blow-up here in the reservoir, is that correct?

A That's correct.

Q Would it be convenient to number those? I know you've got them -- West Gavilan, can we number that one 1? You've got next East Gavilan, number that 2. The pressure maintenance expansion area is 3. 4, being the west half of the west -- the injection project, not west half but the west part, excuse me. And the east part of the injection project being 5, as far as sectors are concerned. I think that might save a little time in having to -- did that -- would those be what somebody might call the 5 cells of the model, is that what you meant?

A Yes, sir.

Q And are all of your calculations, at least, that you made with reference to the various items of this report, including up through page -- I guess through -- maybe you ought to tell me, how many pages in this report are based on the use of that reservoir model that you've been talking about?

A I believe through page 6.

Q Through page 6. How about the items on page 10, 11 and 12?

A Excuse me, you're right. They were also based on that model.

Q Any more past 12 through the back of the book here, what about on pages 16, 16A, 16B?

A No, not at all.

Q So at least through page 12 the calculations that you've made have been based on this reservoir model, is that correct?

A Yes, sir.

Q And what -- what you try to put in these reservoir models, I take it, is the observed data and the observed facts that you have, is that correct?

A Yes, sir.

Q And is that what you've attempted to do in this model that you have?

A To the extent possible.

Q And do I understand that based on that information that you put in that you found the pressure in the 4 and -- the 5 and 4 area here went down due to initial production in that area, and the pressure over in 1, 2 and 3 came down somewhat at the time, is that correct?

A Yes.

Q And then there was a point when injection started in '67 or '68, somewhere along in there, that the pressure began to build-up in 4 and 5 and that's the top two lines that built -- instead of declining from about 1967 or '68, actually increased during the entire period until, oh, until at least Gavilan was discovered in 1983, is that right?

A That's correct.

Q And that's what your model has shown you based on the data and information you put in there.

A That's correct.

Q Now, let's see what the observed facts are during that period of time.

In this entire 4 and 5 area, what pressures did you have in the early time period? Are they shown on this exhibit, page 3?

A In area 4 we have the first two crosses, the first -- first one quite early in Well L-11.

Q All right.

A And then a later one in from Well C-34.

Q The last one in C-34 down here. Those --

A Yes, sir.

Q - those are the only observed pressures that you have to put in your model at that time.

A That's correct.

Q And the pressure was going down.

A Yes, sir.

Q All right. Now, do you have a pressure in area 4 in 1988, or so?

A Not -- not a directly observed pressure, but what I have there around 1988 to try to get some feel, is a pressure taken from Mr. Greer's rainbow map.

Q Was that -- is that what that --

A That point is from the rainbow map simply taking an average position in the rainbow map but instead of using pressure as on that map, correcting to datum.

Q Okay. Observed that -- you consider that an observed pressure?

A It's based on an observed surface pressure.

Q You didn't use the C-34 pressure that was measured in -- in about 19 -- I think it says November of '87?

A No, sir.

Q If you had spotted it on there would it have been about in the same place that you have the plus?

A I don't know.

Q Well, let's see if I understand. You do consider the X you have over here, which is -- looks like it's in '88, to be an observed pressure though.

A Yes.

Q All right. If you connect up the observed pressures in 4, in area 4, does it -- would it appear that the pressure would go down at one angle and then go down slightly all the way over to where the pressure is that you have with the other X?

A If you simply draw lines between points that's indeed the shape.

Q And those would be the observed pressures with lines between them.

A That's correct.

Q In your experience with dealing with this matter now, you've been -- you've been at it longer than I have, about 18 months, or so, 15 months, or so, maybe, in gathering the data and information who have you found to be the most knowledgeable people with reference to the operation of the unit over here, 4 and 5?

A The BMG people.

Q All right. Would that be Greer?

A Mr. Greer.

Q Been here all the time.

A Yes, sir.

Q You find him to be a good professional engineer?

A A superb professional engineer.

Q How about Mr. John Roe?

A Mr. John Roe is available for consultation.

Q Has -- has he also been in that -- familiar with this unit operation during this entire period of time?

A I don't know about the entire -- surely not the entire period of time but familiar in recent years.

Q What if those two gentlemen had during the period of time from when injection started in'67 or '68 had observed that the pressure was declining, not very rapidly but maybe 10, 11 pounds a year, in areas 4 and 5 from the time injection started till 1986, 1987? Would you believe them?

A I would like to see a basis for that statement but I have a great deal of confidence in both those gentlemen.

Q They haven't furnished you any pressures during that period of time, have they?

A No.

Q As I understand it, Mr. Greer has a method by which he can which he can just look at the surface pressures out here and calculate the bottom hole pressures that he feels a lot confidence in.

A Well, particularly now. I'm not sure he would have the same confidence in that in the past in that now he can do that in wells which are gas lift, or high gas/oil ratio wells, in which he feels confident that he has a wellbore full of gas and doesn't have to worry about an unknown liquid level as such.

Q Mr. Roe in the -- in the March, 1987, hearing, that was a hearing that you attended?

A Yes, sir.

Q Let me show you what we've had identified as Mallon Exhibit Fifty-one, which is an excerpt of his testimony from that hearing, Volume II, Page 214, and Mr. Humphries is asking the question.

"QUESTION: -- you had the best of all worlds, what would that curve look like?

ANSWER: For twenty years the unit maintained a rate of pressure decline of about 11 pounds per year.

QUESTION: Which unit, the --

ANSWER: The Canada Ojitos Unit, with pressure maintenance, matching -- attempting to maintain reservoir pressure and produce the reservoir at a rate that approximately matched the gravity drainage rate, the rate of pressure decline, and again I said twenty years, I'm not sure how many years, but the rate of pressure decline was about 11 pounds a year."

Now does your pressure graph that you have used in your model, that your model has produced, does it show a pressure decline for about 20 years during the pressure maintenance project of about 11 pounds a year?

A No.

MR. DOUGLASS: Offer -- well, I don't know, let's -- yeah, let's have it -- I've already identified it as Exhibit 51.

Q Now, let me show you what I've asked to be identified as Exhibit Fifty-two, which is a portion of Mr. Greer's testimony in that same hearing, Page 90, Volume I, Mr. Greer testifies:

"Then in 1976 it picked up a steeper rate of decline and that, we think, was a consequence of our lowering our pressure maintenance gas injection.

Prior to 1976 the price of oil or gas was low enough that we over-injected in the reservoir and by over-injected I mean we injected more gas than was necessary to just replace the oil. To maintain the pressure, of course, we had to over-inject as the oil falls down the structural dip, then it's necessary to increase the pressure in the gas cap in order to maintain the pressure in the producing wells. [But] even though we over-injected we still did not quite keep up with the pressure..."

Does your model indicate consistency with what Mr. Greer testified to about not being able to keep up with the pressure decline during this period of time?

A No there's a difference.

MR. DOUGLASS: We'll offer 51 and 52, Mr. Chairman.

MR. LEMAY: Without objection, 51 and 52 into the record.

Q Let me show you what we've identified as Proponents Exhibit Fifty-three in this proceeding.

On Fifty-three the yellow has -- has that yellow line been correctly connected in the manner that I visited with you about earlier as far as being -- connecting the points?

A Yes, sir, it has.

Q That yellow line appears to be substantially below the pressure that you have found in 4 and 5, is that correct?

A That's correct.

Q Now, I know that you don't have any way of measuring, but I'll show you Exhibit Twenty in this hearing, and I believe the pressure decline that I'm going to be visiting with you about was also shown exactly the same on Exhibit Nine in the March '87 hearing, which -- excuse me, March '88 hearing, which you attended, and I'll ask you if it appears that the pink line shows approximately the same pressure decline as shown on Exhibit Twenty that Mr. Hueni has put into the record? The pink line on the curve.

A Yes, it's qualitatively the same.

Q And his line would be slightly below the yellow line that you've drawn and both the yellow and the pink line are substantially below what your reservoir model shows with reference to areas 4 and 5.

A That's correct.

Q Now, at the March '88 hearing did you also use this same reservoir model that you have here, perhaps not to the extent, but -- or -- well, strike that.

Did you use a reservoir model in the March '88 hearing to make some calculations?

A Yes, I did.

Q Was it one that extended from the east through area 5, 4, 3, and 2? I'm not sure whether it went into 1 or not. Did it?

A As I recall, I don't remember where it ended up.

Q So it -- but it certainly went across the boundary here, the current boundary of what the -- of what we've been talking about as the Gavilan and the West Puerto Chiquito, is that correct?

A Yes, sir.

Q And so that model would reflect the pressure from the beginning of time across that boundary, is that correct?

A Oh, no, it was not intended to do that, not at all.

Q Well --

A It was not an attempt to match history.

Q Well, didn't you testify and didn't you match history for this -- for this 4 and 5 area then?

A Not with that model. That was -- there were really two models presented in that -- in that hearing, one of which was a modeling of qualitatively the good that could be done with a gas plant or taking produced gas to a plant; the second of which was a demonstration model showing the effect of gravity drainage.

Q Would either one of those models have matched this early time history and give us a pressure across the area that we're dealing with here?

A There was no attempt to match history. To match history you have to try to put in the properties as they vary with position across the model, and so forth. There was no attempt to do that with that model work. Those were to demonstrate concepts.

Q Well, I'll offer Exhibit -- offer Fifty-three, Mr. Chairman. I may have not offered Fifty-one and Fifty-two altogether with Fifty-three. Offer all three together.

MR. LEMAY: Without objection they'll be accepted into the record.

Q Let me show what I'm going to ask, for the record, to be identified in the record as Exhibit Fifty-four.

On Exhibit Fifty-four in red has been placed the simulation output for the pore volume average pressure for the simulation study that you put in in March of 1988. Does that appear to be the proper pore volume average pressure that you had in your model at that time?

A Oh, I'll take your word for the fact that that's what it said, but again I'm going to say there was no attempt to match history by putting in the kinds of things in that reservoir, and particularly trying to -- trying to look at the special distribution of properties, and so forth.

Q Well, it looks at the first part of that that you were able to match the -- even better in that model than you are in this one the original measured pressures that you had at that time.

A Well, it may do that but that was not a purposed of the model.

Q And doesn't it also show that the pore volume average pressure follows essentially the same line Mr. Hueni drew, the same line on his extrapolation there, and the same line if you actually connect up the points in the areas 4 and 5 on the map?

A The lines are about the same place, yes.

Q Now wouldn't the observed facts of pressure, the observed facts of Mr. Greer and Mr. Roe and your previous work, and Mr. Hueni's work in this area, all indicate to you that the pressure in the areas 4 and 5 did not do what you show on your model?

A No, it doesn't, because if you put in more than the take out pressure's going to go up.

Q Well, it may not necessarily have to go up but it may have to go some place, right?

A Okay.

Q So if the pressure is going down it means it may be going somewhere else.

A I'll consider that as a hypothesis.

Q In other words, the observed facts would lead you to the conclusion, just like Mr. Ellis' observed facts, was that they overcome and tell you that your model is really not telling you what took place in that reservoir during the twenty years, isn't that correct?

A I'm not sure that we have any observed facts that say that, Mr. Douglass. I see no observed pressures below the line that I projected in my model study in this time period from '71 to '84 or '85. I don't have anything.

Q You have the sworn testimony of Mr. Greer and Mr. Roe, don't you?

A Yes, but I, you know, I would like to study the context. I realize what you say here but are we talking about averages? Did we take a pressure twenty years ago and a pressure twenty years later and look at the total change without worrying about what had been going on? I just don't know the context of that statement.

Q Did you go into that kind of detailed examination of Mr. Ellis about what he saw on the bleeding core?

A No.

Q Is one of the things that happens to cores when they're brought out of wells is that they're washed?

A Yes.

Q Those old roughnecks don't like that mud on the floor, do they?

A Right.

Q Is that a possible explanation of why Mr. Ellis didn't see any oil on the core, that it has already been washed by the time he saw it?

A Well, it might be, but, you know, it was more than just a visual inspection of the outside of the core. It was a look at a lot of that core material.

Q In your model have you calculated what the, with 270-foot fracture spacing, have you calculated how wide the fractures are in that model?

A Maybe I don't understand the question. To me the answer to the question I thought you asked would be 270 feet, but --

Q Well, that's -- this is between the fractures.

A Yes, sir.

Q All right, what is the distance within the fracture; in other words, the fracture width?

A Oh, goodness, I don't know.

Q Is it something you could calculate out of your model?

A No.

Q Nobody's been able to calculate that.

A No.

Q Does your model have a porosity in it?

A Yes.

Q What was the porosity?

A Let's see, if it's summarized on our data here. 0.439. What we tried to do here was use to the extent possible, properties that Mr. Hueni used, focusing on those areas where we felt we ought to look to see whether there would be a significant (unclear), so 0.439, but because Mr. Hueni used it.

Q Now that's a percent, that porosity, is that correct?

A Yes.

Q So it would be 0.00439?

A Yes. It is a fraction.

Q Yes, sir. Now, I believe I didn't understand you correctly, you said these fractures were 270 feet long?

A In this particular model and only because that's what Mr. Hueni used, that I modeled the same size fractures.

Q He used 270 feet apart fractures in his model?

A Yes, that was my understanding of the (not clearly understood) of his computer output. With the -- let me -- let me say, that with the pseudo steady state formulation you can have all sorts of combinations of fracture size and permeability, you know, that can go together in any combination, but what we did, still, is work with a 270 fracture and the permeability that would go with that in his model.

Q Well, I may have misunderstood. I thought you said that's what Mr. Greer said.

A No, no, no. If I said Mr. Greer, I misspoke. What I did is look at the properties that Mr. Hueni used in his modeling effort and said, okay, if I change the things that I think are particularly important, will I get a significantly different result, and the one that really matters, of course, is permeability.

Q Well, let's see, if the fractures, if they were 270 feet apart, they might not go through the reservoir exactly at that, but that would be the -- is that the way the model would look at it, being something like that?

A The way that we actually did this model with what we call a slab type model. Total thickness of a slab is 270 feet with the fracture in it, so we didn't use the geometry that you did. I used a method of modeling which is proposed by a gentleman named (unclear) in petroleum literature, and he said if you model fractures in a slab that's equivalent to many other shapes within the reservoir, notwithstanding what's in the model, it's a slab. The fracture is horizontal.

Q The fracture is horizontal.

A The fracture is horizontal.

Q You have reservoir rock above and below it, then?

A That's correct. The fracture is horizontal. That's equivalent to blocks in the reservoir and (inaudible).

Q In other words, that would be a fracture and then you have reservoir rock and at 270 feet does it have another --

A Yes, it has another fracture.

Q -- another fracture above and in between here is where you say that there is essentially no porosity in that rock.

A That's right. That's our matrix.

Q And in the -- in the -- in the fracture itself it has a porosity of 0.00439, or 0.439 percent.

A Correct.

Q All right, sir. And if you were going to determine -- would that mean that in this direction you've got half of that porosity or each direction is half the porosity?

A Yes, sir.

Q Okay, that would be what, 0.002? 0.0-0-2-2?

A Okay.

Q Is that right?

A Yes, sir.

Q All right, sir. Well, now, let's see, you've got 270 feet, as I understand the distance here. If I wanted to find out how -- how much distance I'd need in that fracture to hold that kind of porosity in that area, that would be -- if I want to convert that to inches, I'd multiply it by 12 inches, wouldn't I?

A Okay.

Q Okay. And then I've got a porosity here of 0.0022, is that right?

A Yes, sir.

Q Now wouldn't that give me the fracture width?

A Yeah, the fracture width used in this idealization of what might be a block or something else.

Q Do you have a calculator on --

A If you'll give me your number, I'll probably accept it.

Q Well, I'm not sure I've got the right number because my multiplier only used 0.002.

A Okay.

Q And using in 0.002 it comes out to 6.5 inches is that fracture width.

A Okay.

Q Do you think the fractures in this reservoir are 6-1/2 inches wide?

A No, but I -- again, this is an idealization. You know, we can also vary the permeability within that fracture and get a fracture flow capacity and that's what matters.

Q Well, that fracture flow capacity could be affected by oil flowing out of this rock up here that you say would not flow, couldn't it?

A Would the fracture flow capacity be affected by the oil? I'm not sure I follow.

Q Well, let me -- let me go back to another question.

Let me ask you in your model here, as I understand it, that you relied on there being essentially no oil that would contribute to production from the fracture, is that right?

A Oil in the matrix with the permeability of the four zeros, or the five, or whatever.

Q And your data in that regard is based on the -- at least in part, and maybe a major part, on this core taken out of the 3-15, is that correct?

A That's correct. That's correct.

Q And I believe you emphasized in your direct that it was dry hole?

A Well, that's an overstatement. It's a marginal well, 5 barrels per day, or perhaps slightly more, so perhaps I overstated it, but it's a very poor well.

Q Oh, it is a poor well. Well, then, if it's out here in one of these tight fracture blocks that Mr. Greer says are an acre or so, then that matrix is producing out there, isn't it?

A Depends on whether that well's been hydraulically fractured, which is virtually essential to get production in this area.

Q Well, I understood Mr. Greer's testimony and really I wasn't at the first two hearings, I understood him to testify that you had to essentially frac all these wells and you couldn't get any production before you did.

A That is my understanding, too. You have to hook up with the natural fractures; the odds of hitting one with drilling are, you know, above zero but not much.

Q Well, the odds are sure a whole lot greater when you've got these fractures 270 feet apart than you do when they're 6 inches or 12 inches or 2 feet apart, don't you?

A The odds are less or greater?

Q Well, less. The odds are greater of hitting a fracture the closer they are together.

A Yes, sir, I agree with that.

Q And when you want -- when you put them out 270 feet apart, you're really stretching the odds out about whether you're going to get anywhere close that you can even frac into one, aren't you?

A Yes.

Q Well, let me get back to 3-15, that that well is in one of these tight blocks that you -- that Mr. Greer described, and you're producing oil from the matrix, aren't you?

A I don't know whether that well has been hydraulically fractured.

Q Well, let's assume it has. Let's assume it has been fractured, just like all the rest of the wells. Aren't you producing well out of that well out of the matrix?

A My answer would be no.

Q Now, let me visit with you about this boundary protection plan Mr. Greer has.

A Yes, sir.

Q Now the boundary protection plan that Mr. Greer has is in part the restricted rates, is that correct?

A I really shouldn't speak for Mr. Greer. The general thrust of what he's explained to me, and this is very much subject to correction by him when he testifies, but I think the general thrust is a testing program to assure comparable pressures at offset wells across the boundaries.

Q But the boundary protection program, I believe, that you indicated, has been in effect since January 1, '87.

A The protection plan in effect since January is not a formal plan. Mr. Greer will propose a formal plan administered. The current way he perceives that he can protect the boundary is simply to drill a well offsetting another well and try to not have migration either way.

Q Well, did you understand the boundary protection that's been in since 1-1-87 keeps oil from moving from area 3 to area 4, I mean area 2 and 1?

A That's the objective of offsetting wells.

Q Nothing in that boundary protection plan keeps the oil from moving from area 2 into area 3, though, is there?

A There's nothing to assure the oil won't move the other way, either, Mr. Douglass. It's simply an attempt to offset and protect the unit.

Q My question was there's nothing in that boundary protection plan of 1-1-87 that keeps the oil moving from area 2 to area 3?

A There is nothing in the plan to keep oil from moving either direction except an attempt to produce offset wells.

Q Mr. Lee, let me ask you to turn to page 16B.

Now I understand your concept of this reservoir to be that there's just practically these major fracture systems out there and no contribution from the matrix to those fracture systems.

A That's probably some overstatement but there are clearly microfractures, these are observed; they have some contribution. It's just I don't see 80 percent of the oil in a system like this. I would see a very small fraction.

Q What percentage of oil do you think is what we've been calling a major fracture system or what you've called a major fracture system?

A Well, it's, you know, I think for -- for talking purposes virtually 100 percent, with a minor contribution --

Q Okay, will you --

A -- from these microfractures.

Q Well, you and I are in agreement now with what your position is, that one, you think there is essentially no contribution from the matrix and essentially 100 percent of the recoverable oil from the major fracture system.

A Essentially, with that qualification.

Q Now, on 16B do I understand looking at 16B that it shows that when you get to zero relative permeability as far as oil is concerned, that you've got a 40 percent gas saturation.

A Yes, sir.

Q Does that mean that in this major fracture system that we've got here, that when you get down to zero permeability to oil you should have a 40 percent gas saturation, or when you get at 40 percent gas saturation you're not going to have any movement of oil out of the major fracture system?

A Yes.

Q And left in that fracture system with the 40 percent gas is going to be 60 percent of something else.

A Right.

Q And that some thing else is -- what's the water saturation?

A Oh, pretty small in the fractures.

Q 10 percent?

A Perhaps.

Q Is that high or low, I don't know?

A I don't know.

Q Well, if it was 10 percent, then we're going to have 50 percent oil saturation in that fracture.

A Okay.

Q In this reservoir that we're dealing with, with that kind of characteristics, what's to keep you from producing down to depletion and then waterflooding that fracture to get that 50 percent oil saturation?

A Nothing.

Q Do you have your input data and your model printout for the exhibits that you've given us here?

A Yes, sir, I do.

Q May we have a copy of it? I know you can't give it to us right now but when you can?

A I probably can. What specifically would you like?

Q All of it.

A Well, what are you calling (unclear)?

Q Well, I think the computer printout

shows input and what it was in various stages.

A Yeah, but I mean, you know, we've had several different calculations; the tank model?

Q Yes.

A The unsteady state matrix flow?

Q Yes.

A Okay.

Q You got any more?

A I think that's all.

Q Hope it is. In your tank model did you have a gas cap?

A Not initially.

Q Was there a gas cap initially in this reservoir?

A Virtually impossible to determine.

Q Do you know what volume of gas that you had in the -- you started out with no gas cap.

A Started out with no gas cap.

Q Okay. Have you -- have you prepared a report or have you (unclear) a televiewer log with reference to the core that Mobil took?

A I've heard testimony on the televiewer log.

Q And they -- indicating that there were fractures 2 to 4 inches apart?

A They indicated that there were fractures and the judgment is does that constitute a major fracture or does that constitute a local phenomenon which quickly fizzles out.

Q You've, on your Exhibit Two, you've calculated what -- what movement of reservoir barrels occurred in a period of June 30, '87, to February 23, 1988, is that correct? Is that 24,000 barrels?

A Yes, sir.

Q If the pressure in the 4 and 5 area had been approximately to this pressure level that's shown by connecting up the points off the -- in this area that you have on your Exhibit One, could someone calculate, using Mr. Powell's maps, as you did, the movement of fluid from 1, 2 and 3 into area 4 and 5 when the pressure equalized along what we've called the proposed boundary?

A I think I understand the question but let me ask you to ask it again.

Q Sure. My question is that if you use the pressure from actual measurements in 4 and 5 and use Mr. Powell's maps, could you make a calculation in the other direction that you've made along the boundary, along the same boundary that you'd made?

A Oh, the answer is no. The -- the assumption on which my calculation was based was that there is no pressure change and that's based on Mr. Powell's observation.

The only other, in the other areas there was an observed pressure change.

Q Well, if you would be able --

A So, you know, so there;s expansion of fluids and things like this that have to be taken into account, whereas I could just look at migration equals injection less production.

That's why I went to the tank type balance, to handle the more complicated situation in which pressure is changing.

Q With reference to those 624,000 reservoir barrels that you can't account for in your calculation, do you think they could have gone to the same place that Mr. Greer and Mr. Roe saw -- realized they were going to when the pressure declining even though they were over-injecting?

A I think that oil went across that alleged barrier.

Q I understand you think that's where it went but it also could have gone in the same place where the gas went or the pressure went during the 20 years that Mr. Greer and Mr. Roe said the pressure was declining in this 4 and 5 area even though they were over-injecting.

A Well, this is a hypothetical place.

MR. DOUGLASS: Pass the witness.

MR. LEMAY: Mr. Pearce?

MR. PEARCE: Nothing, Mr. Chairman.

MR. LEMAY: Mr. Lopez? Mr. Lund?

MR. LUND: Yes, sir, please.

CROSS EXAMINATION

BY MR. LUND:

Q A quick question, Dr. Lee. The exhibit that you passed out on Monday, the 7-page exhibit, were you aware that this was going to be an exhibit produced in this hearing?

A Yes.

Q Thank you.

MR. LEMAY: Additional questions? Mr. Chavez.

QUESTIONS BY MR. CHAVEZ:

Q Dr. Lee, on your Exhibit Number One, page 2, how far north and south do these tank models go beyond the area that's mapped on page 2?

A Actually the tank lengths are only 8 miles in the model but what we do is actually put every -- every well that's between these, let's call them vertical boundaries, put them in the tank, even though there may be more than 8 miles of production in some specific areas. We just include that production in the tank. So I hope I'm clear when I answer 8 miles long with in some cases wells a little bit outside of that put in the tanks.

Q Do you agree with Mr. Greer's statement from early hearings that the reservoir, at least the West Puerto Chiquito Mancos Pool, has greater permeability in the north and south direction than in the east and west direction?

A Oh, I think there's very substantial evidence that that's so, at least in some local areas, such as in the current pressure maintenance area.

Q In your studies did you take a look at wells depleted further south in the pool, for example, the Amoco well that's completed in Section 25 of Township 24 North, 1 West?

A I was aware that activity like that was going on but I really hadn't looked at it there.

Q Could you look at page 10 of your Exhibit 1?

A Yes, sir.

Q At what point did Mr. Greer begin over-injecting in the pressure maintenance project? Would you identify that on that map?

A To identify that I'm going to have to look at page 3, I believe it is.

I'm going to look at page 3 because on page 3 we will see a time at which the pressure in the entire reservoir clearly is beginning to increase, meaning more injection and withdrawals. That time is about 1972, in that range. So, 1972, you could put a tic mark on page 10.

Q Did you verify that date with the injection and producing volumes in the pressure maintenance project?

A Yes. You know, that's -- that's really what caused the turnaround in the graph on page 3, and that was based on observed and reported injection and production volumes.

Yes, I checked it several times.

Q If you were to draw a line on the zero point on the left side of your graph on the Y scale and extend it -- start on the left part of the scale and extend it all the way to the right, at what point would you find that the pools may be what we call balanced so that the -- the oil had been perhaps returned back to the pools the way it was originally found?

A Well, if you take this graph literally, and I think I've drawn such a line, and it's about 1977, and I would caution that I think about all that we can really hope for here is an indication of direction and if anything, the exact time period and magnitude I think would be pushing this sort of modeling well beyond its limitations.

Q Could you be within one year as far as --

A Oh, I think we ought to be within, you know, within plus or minus two years either direction. It's a reasonable probability.

Q Do you recall when the discovery well first started producing in the Gavilan Mancos Pool?

A 1982, I believe, or late '81.

Q And if you identify that point on your graph, what would be the cumulative amount of oil which would have migrated towards the Gavilan Mancos Pool at that time?

A Again taking these numbers literally about 200,000 barrels, but I would caution not to (not clearly heard.)

Q Do you find that's in contradiction with the original bottom hole pressures that were found in the

Gavilan Mancos Pool which were below what would have otherwise been virgin reservoir pressures?

A I don't know about those original pressures in the Gavilan Mancos Pool. The first one was substantially lower even than the second one and the second one came several years later, you know, so maybe we have maybe a data problem. The first one was the Gavilan 1. What I -- what I have found about that well is it was a poor well with low permeability and the significance of that is that in this heterogeneous reservoir there may be wells in the area which are, you know, given a little bit of production and it may take forever to build up; not receiving pressure support for wells later; you know, there are just all kinds of potential local anomalies.

But again I would point out the significant fact that if we take the Gavilan 1 literally, you know, the Rucker Lake Well was quite bit higher later. So I don't know, I probably am not answering your question, but those, you know, those two pressures were lower than the discovery pressure there, if either of those is a discovery pressure, is lower than the discovery pressure in the Canada Ojitos Unit. All the pressures in the unit have been high with this over-injection.

Q Well, looking at 1987 on your page 10, how much oil, cumulative, would have been moved to the

Gavilan Mancos Pool, say, at the beginning of 1987, according to that graph?

A 1,600,000 barrels, perhaps.

Q And if at the beginning of 1987, or let's say the end of 1986, the Gavilan Mancos Pool had produced 3,000,000 barrels; a little over half of that you would have attributed to migration from the expansion area or from the West Puerto Chiquito Mancos Pool?

A Oh, I don't think that's necessarily true at all.

In the first place, I don't think we produce necessarily a significant fraction of that which migrates.

MR. CHAVEZ: Thank you, that's all.

MR. LEMAY: Thank you. Additional questions of the witness? Commissioner Humphries?

QUESTIONS BY MR. HUMPHRIES:

Q Dr. Lee, Mr. Hueni's theory, I don't -- I guess his conclusions had to be derived or his information led him to the conclusion that there is a dual porosity system there and that the barrier exists. Any you find just the opposite, that there is no dual porosity barrier -- I mean no dual porosity system and there's no barrier, is that correct?

A Yes, sir, that's -- those are my conclusions.

Q I like to think that most things make some sense, with the possible exception of me having run for office. I like to think that I have some common sense and it's hard for me to disregard Mr. Hueni's idea that a difference in pressure in the fracture system would lead to some contribution from the surrounding material.

You don't believe that a matrix exists in any form or that it's a very limited matrix?

A I'd say a very limited matrix, and I think you're on to the fundamental reason. Certainly if there were a matrix with high enough permeability, whatever high enough is, and there were a pressure difference, that matrix would at least leak some fluid into the fractures.

I think where we have a difference in perception is on whether there is a matrix with permeability present in this pool and based on the core data that I've seen and the size, the apparent size of the fault blocks, I'd say that whatever oil can come in is very limited in amount.

Q I think it was my term. but the concept of a one-way movement is a little hard for me to understand. I know water kind of has a tendency to go one way and that's downhill. They tell me it moves uphill for money but I'm not sure that that's necessarily true in this case. How -- how could even a dual porosity system not, given a 3-dimensional fracture system, it must pass back and forth through the matrix if there is matrix contribution, how could that only work one way, or is -- I realize your contention is different but you might help me to understand that; nobody else has been able to. I understand the theory of the reduced pressure leading to contribution to the fracture system. I don't understand why they can only be one direction.

A Well, the one direction that I think we're talking about, please correct me if I'm off base on the concept, we're talking about the tendency of oil to imbibe back into the fracture system and then not be further produced. I think the analogy that's been used of a sponge is a good analogy. If you put a sponge in water it will imbibe that water. Now you can apply force and get it out but if you don't do anything it's going to stay there and it may take, you know, the smaller the spaces in the sponge the harder you may have to push to get it out. You might have tiny spaces.

In a reservoir there may just not be enough force, namely difference in pressure in the matrix and the fracture, to produce it back out, but there, on the other hand, there may be. It may not be a one-way phenomenon. It depends on the force available to push that oil back out.

Q I think Mr. Chavez has asked this same question but I want to make sure I understand it.

Is the permeability variation that you perceive consistent and parallel along the alleged barrier?

A I think I understand the question. Let me -- I'll try to --

Q How far north and south do you see it going and is it consistently parallel to that barrier, because that's what the tanks sort of indicate?

A Mr. Greer has described in previous testimony what he calls permeability plateaus with -- with reductions in permeability at various levels, but on a given level very high permeability going north and south in this field. You know, I don't know how high but very high permeability north and south, and perhaps rather an excellent permeability east and west, and then perhaps some geologic feature which I don't think the term "barrier" is appropriate, if you'll forgive me, but at least a reduction in permeability, across which there is a significant drop in pressure and then another permeability plateau, again pretty high east/west but probably a little bit higher north/south with essentially equal pressures for many miles north and south.

Am I getting at your question?

Q Does that -- would that permeability -- what's a good word to use, pressure differential, or permeability variation, does that extend to the boundaries of the reservoir, perhaps beyond the pool?

A I don't think it extends as regularly as the boundary but that permeability variation of a sort extends throughout the pool; for example, as I've observed earlier, in Gavilan there are currently very substantial pressure gradients within Gavilan that even though we have all, both sides, always refer to Gavilan being excellent pressure communication.

What does that say? That says some, at least some local areas have much reduced permeability offering considerably more than the usual resistance to flow would cause this gradient. So, you know, we have -- we have heterogeneities through out the pool, although not necessarily of the same kind in all places in the pool.

Q I think Mr. Douglass has asked you about a fairly significant discrepancy between Exhibit Three that you had used earlier and Exhibit Fifty-one and Fifty-two from an earlier hearing.

Would you briefly explain that discrepancy as far as you see it, the one where you're indicating essentially no pressure drop and the other where Mr. Greer and Mr. Roe both indicated that there had been some pressure drop over a long period of time?

A Well, I don't know which of the simulations Mr. Douglass was showing me the --

MR. DOUGLASS: I think page 3. He said Exhibit Three.

Q Excuse me, page 3 and exhibit --

MR. DOUGLASS: Exhibits Fifty-one and Fifty-two.

A Okay, you were not referring to the previous modeling work that I had done but to the testimony of Mr. Roe and Mr. Greer, a comparison of that to page 3?

Q Yes, sir, where one indicates a protracted decline, I think it said probably 11 pounds per year, and the other -- other doesn't seem to indicate that.

A Yeah. I've not seen those transcripts before and I don't know the context. I see the possibility that in the case of the 11 psi per year that that's taking a pressure at some time and a pressure at a later time, and perhaps not taking into account what happened in between.

I don't know that but seems like that's a possibility. Certainly if you look at current pressures in the pool, they are dropping substantially below pressures some years ago, even though they may have risen in the intervening time.

So, you know, I just don't know the context of the statements.

Q Yesterday Mr. Elkins made a comment and I believe he said that he wasn't extremely familiar with the West Puerto Chiquito Pressure Maintenance Project, but he said it appeared that the production rates were exceedingly low, and you've indicated that you are fairly familiar with the West Puerto Chiquito Pressure Maintenance Project and perhaps the whole Canada Ojitos Unit.

How would you respond to that? I mean that was kind of a question in my mind. Why would its production rates be exceedingly low if it was not some reservoir management?

A It is. It's very specifically for reservoir management reasons.

Mr. Greer has studied the possibilities offered by gravitational segregation; the tendency of gas when it's in original solution to move upward and oil to move down.

If you go slowly, produce slowly, withdraw slowly from your well, the gas has time to get up and get away from the oil and you can produce low gas/oil ratio wells for a long period of time.

If you produce more rapidly, and there's a different definition of what's rapid for each individual reservoir, but if you produce more rapidly, you might create big enough drawdowns that the forces, the pressure drops within the reservoir might tend to draw the gas before it's released into the producing well; might not give it a chance to segregate under the influence of gravity.

You might have more pressure drop and more gas released, and that would hurt recovery. You could end up with a lot of your reservoir energy being dissipated and you would lose the opportunity for this nice, complete segregation of gas and oil and the possibility of producing low gas/oil ratio wells for many years.

Mr. Greer has identified this possibility and has chosen to operate the Canada Ojitos Unit to take advantage of this method of operation, and I think the field data shows that he has successfully done that. He's had low gas/oil ratio wells. They appear to be approached by a sharp gas/oil contact indicating rather sharp discontinuities between the gas phase and the oil phase that appears very suddenly and he's taken, you know, he's gotten the maximum amount of recovery that he could by going so slow.

Q Is it possible that this 2-mile wide area that is in the east -- or west end of the West Puerto Chiquito but it's not in the pressure maintenance area, and it seems to be an area of contention, is it possible that that area has some unique qualities that may not be similar completely to either Gavilan Mancos or West Puerto Chiquito? I mean you even demonstrated a slightly different tank in your presentation.

A One of the reasons that I chose it as a tank was because it is an area of serious contention.

Does it have any unique properties? Well, it's in another permeability plateau. It's -- it's in a different permeability plateau, let's say, from wells up structure. It is in communication with areas up structure but, you know, the characteristics are -- are somewhat different. The heterogeneity, perhaps, the form of heterogeneity begins to vary, but the fact is it is in pressure communication and in my judgment the whole pool is in pressure communication. It's just that the kinds of permeability differences vary. For example, Mr. Powell's maps showed, I think, simply very high north/south permeability in the existing pressure maintenance project area, and, well, that accounts for those contours that it showed.

And then when you go into the expansion area he showed contours of -- of different forms. Well, that may indicate that within that portion of the reservoir you may no longer have such very high north/south permeability. You may get more north/south variation in pressures.

Q Is it possible that given the fact that the Proponents and Opponents have very significant experience with the two separate pools as they exist now, and some common experience with this area of contention between the pool boundary and the alleged barrier, that some of the possibilities that Mr. Hueni has proposed could in fact be correct about the Gavilan Mancos and perhaps not correct about West Puerto Chiquito and in transition in the middle?

A It's conceivable. I really don't think it's likely. I think you're talking about -- particularly about the matrix containing oil and --

Q And the so-called reverse rate sensitivity.

A Yeah, I suppose that's conceivable. I guess my judgment is it's not likely.

Q Well, it's obvious that the opinions are diametrically opposite. The results of one action in one case demonstrates or assumes dire results and in the other assumption it assumes dire results, and it sort of leaves this Commission with the task of trying to sort out a lot of professional high quality testimony and no questioning or impugning people's integrity but with directly diametrically opposite results, one says pressure maintenance enhances it and one says it ruins it, it leaves us with, wait a minute, I'm wondering if there isn't a difference from just based on experience with the two people's specific experience with the pools.

A Well, I don't know, and I, you know, I certainly appreciate the dilemma that you're in, and I think the real difference in opinion comes from, you know, it ultimately comes down to whether or not this is a dual porosity reservoir, you know, that's what is dominant in whether or not there should be a gas injection project. We've had all sorts of testimony about all the bad things in the Spraberry, and so forth. Well, they're because it had a matrix that can hinder it.

Now if it were simply fractures with some significant amount of oil in it, and there were a place to inject gas at a relatively high structure position and produce oil low enough that the gas didn't channel through, then I would think that a gas injection project would work in Spraberry or anywhere else, in any place that had a place where you could keep the gas above the oil. You know, the fundamental consideration is, is it dual porosity or not?

So I, you know, I think it's just a difference in perception, whether that's the case or not.

Q Thank you.

MR. LEMAY: Mr. Brostuen.

QUESTIONS BY MR.BROSTUEN:

Q Dr. Lee, I refer you to your chart on page 3. I believe you stated that the pressures for the -- or indicated your pressures for the, I assume, your point at the center COU, I think the number 4 tank, to Mr. Douglass was taken from the rainbow map. It's not a measured observed pressure, is that correct?

A Yes, sir, that's correct. The rainbow map is an observed pressure.

Q Yes, sir, I understand that.

A Okay, but yes, it's from the rainbow map, yes.

Q And then Mr. Douglass asked if there was a pressure for that tank for November of 1977. Is there a pressure? Was there a pressure taken from a well in that tank that is not on this chart or was that a mistake?

A I don't know. I just don't know. Let me -- I do think I should tell you what -- what we very carefully tried to take into consideration in providing pressures which would find the best possible match.

Every pressure which was ordered by the Oil Conservation Commission was -- was included, no exceptions.

Secondly, we tried to include pressures from Mr. Hueni's, I believe it was Exhibit Nine.

We included the earliest pressures in Gavilan thinking that they would be of significance, and then simply because of gas we chose three pressures from the rainbow map. I think those are good quality pressures but we wanted to minimize the use of those because that's controversial and to the extent possible we wanted to minimize the controversy about the pressures that we chose to match.

Q Which -- which other pressures did you take from the rainbow map?

A Well, the highest pressure that you see on there is 1.

Q Okay, the X up in --

A Yeah, the X up near the top.

Q Okay.

A The one that I've done a little bit of struggling with to identify for you, is kind of buried among a bunch of other pressures. If I can look at my back-up material here; all right, the pressure in tank number 3, the West Canada Ojitos Unit expansion area, the pressure near 1-1-88. It's value is 1015 pounds.

Q That would be a triangle?

A Yes, it would be a triangle at 1015 pounds.

Q Okay. Thank you. You mentioned that it included all the pressures that were required or resulted from the testing that was required by the Conservation Commission. Are there other pressures that you're aware of that are observed pressures that have not been reported to the Commission or that would support what you have here? Are there other observed pressures that were taken by Benson-Montin-Greer or others that you might be aware of?

A No, other, you know, other than the pressures on the rainbow map, surface pressures, which we don't seem to be able to get quite the credibility for that we think in general they deserve.

There some -- some build-up tests. We tried to minimize the use of those because of lots of differences of opinion on how to extrapolate those, fully built up, and so forth.

So basically our data set out is as I described to you earlier.

Q Okay, thank you. On your page 26, the Horner semilog analysis, and I believe in the testimony you expressed the hump (not clearly understood) the Horner time, approximately?

A Yes, sir.

Q (Not clearly understood).

A Not just that hump, the whole shape of the curve.

Q The whole shape of the curve?

A You can have -- phase redistribution can cause a curve shape, let's say that hump weren't there, to just come up sharply, level out, and then come back up again without any hump. That can be due totally to phase segregation in all these reservoirs, and that's really the interpretation that Mr. Weiss gave this, you know, I'm sure he said that that period, that little hump is just bad data and basically honored the other data.

Q Okay. Phase segregation is affected by, and the affect of phase segregation upon a Horner analysis is affected significantly by gas/oil ratio and the production, isn't that correct?

A Generally you need significant amounts of oil and gas --

Q That's correct.

A -- in the wellbore.

Q That's right, so the higher the percentage of oil, the greater the effect on the (unclear) distribution?

A No, you need quite a bit of gas. In other words, if you have very little gas --

Q Certainly, certainly, you have to have, but do you know whether -- what the gas/oil ratio and production rate was just prior to shutting in this well for --

A Yes. Excuse me, gas/oil ratio for both these two wells that we show here is in the range of 3-to-4,000 standard cubic feet per stock tank barrel. The production rate prior to shut-in, I can get that number for you if you could give me just a second.

Q Okay, I wish you would, please.

A On the Mobil Lindrith Well the rate just prior to shut-in was 221 barrels of oil per day; gas/oil ratio was 4023 cubic feet per barrel.

On the High Adventure the rate just prior to shut-in was 162 barrels per day; the gas/oil ratio was 3605 cubic feet per barrel.

Q Do you consider the volume of oil being produced just prior to shut-in and the volumes of gas being produced to be sufficient, the phase redistribution resulting from that in the wellbore would be sufficient to cause the effect -- or result in the interpretation you have that what we're seeing is phase redistribution and not dual porosity?

A Yes. Well, you know, I don't think there's much question about it in the case of the Sun High Adventure.

The only other major possibility I can think is a leak. You know, that happens, but that leak seems to have healed itself because the pressure then later built back up.

Q The reason why I introduced that second well, which is clearly phase segregation, is to show that the characteristics of this formation or the producing, the well operations, the way wells are produced and the gas/oil ratios if they go any higher, this is a combination of circumstances in which phase redistribution appears with some frequency in well tests. In some cases it's very clear. Now when it's very clear, that means that there's a possibility that it will affect tests in more subtle ways, like maybe giving a shape that looks like dual porosity reservoir.

I think in the case of the Lindrith, though, we still do have a little hump, which makes the case even stronger. But, see, what we're trying to look for is a consistent pattern. We really don't see a consistent pattern, a curve shape, which I think can reasonably be interpreted as a dual porosity reservoir, and that would be evidence that I would like to have before I would conclude that it's a dual porosity reservoir.

I worked a lot in dual porosity reservoirs. Currently I'm working in a major research effort for the Gas Research Institute, looking at the eastern Devonian shales, which is very clearly a dual porosity reservoir.

By and large the build-up tests there have that shape, you know, you test one, you see that shape; you test another, you see that shape. It's very characteristic. We just don't see that pattern here, but we do see some semblance of a pattern of phase redistribution. It's because we see it with some frequency I saw I would conclude that as a probability, not certainty, but a probability, that that phase redistribution is the cause of the shape in wells such as the Mobil Lindrith B-37.

Q Thank you, very much. That's all.

QUESTIONS BY MR. LEMAY:

Q Dr. Lee, back again to your page 3, I'm trying to focus on injected gas, how much there was and where did it go, I guess.

The excess injected over production occurred between you say 1973 and '77, or what years are we over-injecting?

A It's going to be based, you know, I can't tell you exactly. We can look at the production statistics if you want, but I think generally whenever the pressure is going up in a reservoir as a whole we're over-injecting. Well, the pressure in the reservoir as a whole starts going up about 1973.

Q Okay, that's assuming where you don't

have pressure points that your analysis is correct.

I'm trying to get back to the assumptions where you have a system where you put in gas and you take out gas and oil, I'm assuming there's a net balance there of more gas being injected than is being expelled.

A Yeah, right.

Q No release points.

A Yeah, and you know, that's not an assumption, and I don't -- I don't think that that's a point of controversy here. The -- our opposition may think that there's another explanation for why over-injection didn't result in effects that they're looking for but there's no question but what during this time period from about '73, to probably '84 or '85, there's no question but what there was more injection than there was production. We have the injection/production statistics to look at and if we can see that we injected more that we produced, then by definition that's over-injection.

Q Right. Do you know how much gas net in that period of time has been over-injected?

A I -- I can get those statistics for you. I don't have them at my fingertip and it may take some work. Would you like for me to provide those to you at my earliest convenience?

Q I think it might help, only to the point we're trying to talk about degree and also if there are some statistics as to when that over-injection by year occurred, so there's a possibility it will match in with pressure.

Mr. Kellahin.

MR. KELLAHIN: Mr. Chairman, we would hope to provide that to you during the period which the Commission will call back witnesses for additional questions.

MR. LEMAY: That would be helpful.

MR. KELLAHIN: And if that might be a time for Dr. Lee to provide that answer we'd appreciate that opportunity.

MR. LEMAY: We'd so much appreciate that. It is an issue we're trying to focus on. Thank you.

Q One other point with your broad range of experience, you mentioned Devonian shale dual porosity, and focusing on that issue, are you familiar with any reservoir with a single fracture porosity system, no matrix, that has been quote successfully waterflooded for pressure maintenance?

A I think we have a perfect example right here and this is the Canada Ojitos Unit, the West Puerto

Chiquito. I think that project is succeeding admirably, and if you want a rock that's just like the rock we're considering in Gavilan, or at least pretty close to it, you know, you just can't find a better analogue.

Q That might be debated by the other side, whether that was successful or not. Maybe that's a good point to debate, but I'm looking beyond this particular example, of any -- any other fractured shale, highly fractured limestone, anything without a dual porosity system, where there's been a successful pressure maintenance project that you know of.

A No, I don't have a list of either successes or failures. I would have to go through the literature and talk with (unclear). I cannot provide you either successes or failures.

Q Well, where it's been tried, are you familiar with any situations where it's been tried?

A Well, what I'm not sure of is whether there was, you know, whether there was matrix, and that's why I would have to give that considerable thought.

Q I didn't want to put you on the spot but I thought it would help us with reference if we could get another example.

MR. LEMAY: I have no further questions. Is there anything additional? Yes, sir, Mr.

Kellahin.

MR. KELLAHIN: Mr. Chairman, I would prefer to go last in discussing questions with Dr. Lee and Mr. Douglass has said that Mr. Humphries' question has prompted some additional questions for Mr. Douglass, and it would be my preference to have him complete his examination before I talk to Dr. Lee.

MR. DOUGLASS: Thank you.

MR. LEMAY: Fine. Mr. Douglass.

RECROSS EXAMINATION

BY MR. DOUGLASS:

Q Dr. Lee, let me ask you with reference to what would be a logical explanation for what we see out here in this area.

First of all, I understand you don't think the barrier is there.

Assume with me at least in this series of questions that there is a barrier there. Would you agree that east of the barrier we have a very steeply dipping, fractured reservoir, according to your examination or understanding of the area?

A Yes, sir.

Q Have you made any calculations in that are how effective gravity drainage would be as a drive mechanism east of the barrier as we say, or where it approximately exists on the map that we presented?

A Yes. I presented testimony to that fact.

Q Would it be an effective drive mechanism?

A In my judgment, yes, it would.

Q And if you added gas to that it would assist the gravity drainage provided you didn't put in enough gas where it bypassed the oil and went to the wells, is that correct?

A Yes,

Q As I recall, the area east of the barrier as we show it, has been produced roughly up to an average of about 1000 barrels a day over its life, would that be about --

A I'll take your word for it. I'm not sure. I only know current rate but that's probably about right.

Q I think we did some figures on another exhibit that showed what its average has been, 312,000, or something like that. It was even a little less than 1000 barrels a day.

Now, one of the problems that you would

have with that type of thing is that that you think there has been over-injection in that area, so where did the gas go, is that right?

If there was a barrier here, then that gas had to go somewhere.

A If there were a barrier there I would think the pressure would have gone out of sight.

Q Is there a possibility then that this gas has been leaking off somewhere up structure in this --

A Mr. Greer has worried about that possibility, not because of, you know, any indication it was, but since he began to inject gas, he's worried about the surface and he had looked hard for that.

Q The -- one of the exhibits we put up here showed that this Boulder Field, which I understand is just north of here in the Mancos formation had recovered on the average of about 900 barrels per acre. That would be an extremely high recovery down here in the area that we're talking about, wouldn't it?

A Yes.

Q Do you know if any investigation has been made to see if that might be the source for where this over-injected gas went during this period of time?

A Oh, I don't know of any investigation, but I know there's a pretty strong feeling that there is very poor communication between this area and some of the areas to the north.

Q Well, it wouldn't take much communication for gas to move through the formation, though, would it?

A It -- it would take permeability over a very considerable -- over a very considerable area, continuous permeability, and with -- well, I'll stop there.

Q The -- and, of course, if you were causing a greater pressure differential, that is, if you were producing those wells up there in Boulder, causing a larger pressure differential than Mr. Greer was producing his wells even closer to the injection source, the gas might still move and probably would move to the area of lower pressure, wouldn't it?

A Given permeability, gas would move from high pressure to low pressure.

Q That is one object that or one physical law I think we're all in agreement on, is that fluid moves from high pressure to low pressure.

A Yes, sir.

Q Now let's -- let's go over in the area, assuming the barrier is there, and we have this Gavilan and expansion area. Let's assume that is one common reservoir. I believe we visited in March of '88 that although you hadn't done any specific calculations you were satisfied that if you were going to use gravity segregation as a producing mechanism in that area because of the low relief that the rates from the well would probably be below the economic limit. Is that a fair summary of our visit last time?

A The rates would be -- would be much lower than in the Canada Ojitos Unit. Just how low, I don't know about that.

Q If the barrier exists and if there is a separate reservoir that consists of the Gavilan and the pressure maintenance expansion area, in your opinion would that area, if it were separate from the injection project, would it operate under a solution gas drive mechanism?

A Yes.

Q Under a solution gas drive mechanism if you increase the rate of oil production should the gas/oil ratio go down if you lower the bubble point?

A No.

Q If you're in a solution gas drive reservoir and you lower the bubble point and the oil rate goes up and the producing ratio goes down, doesn't that indicate to you contribution by the matrix to the oil production?

A Not necessarily. There is an alternative explanation. You know, it could be simply the way of producing the well.

Q But it also just as reasonably could be a matrix contribution.

A That's a possibility. I think we need to look for a possibility that's consistent with all the facts that we see, and then we have some suggestions for other possibilities.

Q But it would be a reasonable explanation.

A It would be a reasonable explanation if we could verify by finding a matrix with permeability, yes, sir.

Q Now, I think Mr. Humphries had probably the same problem I do in understanding, is that we've got a matrix that has a large amount of oil and it's connected by a fracture system and we've created a pressure differential where the oil goes into the fracture system.

Why, at some point in time can't I put gas back in that reservoir and start pushing that oil out of that matrix?

A Well, the matrix prefers to have oil in it relative to gas. It's like a sponge, it would rather have water than air.

You can push the water out of a sponge but you, you know, you've got to push it out with air under pressure.

Q Well, although I know you don't agree with what's the concept that the Proponents have with the reservoir, if they're concept of the reservoir is correct, then gas injection is not going to help recover any additional oil out of the Gavilan and the pressure maintenance expansion area, is it?

A That's correct.

MR. DOUGLASS: Pass the witness.

MR. LEMAY: Additional questions? Yes, sir, Mr. Pearce.

MR. PEARCE: Real quickly, Mr. Chairman.

CROSS EXAMINATION

BY MR. PEARCE:

Q Dr. Lee, I notice in the righthand side of the map, base map, there is a niche in the Canada Ojitos Unit which has some wells in it. Do you know anything about those wells?

A No, sir, I don't.

Q You don't know if they were initially unit wells?

A No, I don't.

Q You mentioned earlier that you and Mr. Hueni in your opinion agreed relatively closely on the possible recovery, and your example was his low pressure gas injection scenario presented at a previous hearing, is that right?

A That's correct.

Q And you remember that he did not agree that high pressure gas injection would be beneficial at all?

A That's correct.

Q And were you in the room when he has discussed at this hearing that in view of the effects of imbibition he now believes that no gas injection would be effective in this reservoir.

A That's correct about that. I was using his example simply to serve as a qualitative check on the magnitude of the answer. Of course, his previous calculation did not include capillary effects and therefore he would not have seen any effect of imbibition and therefore, even though it was a dual porosity reservoir, in a lot of ways it was operating like a solution gas drive reservoir, the same model that I have, and therefore it's a check if we get roughly the same answer with a pressure injection project.

We did. I think it confirms that my

simplified calculation (not clearly understood) correct.

Q All right, Dr. Lee, looking at page 2 of your Exhibit Number One, the exhibit in which you set out the cells or tanks using your analysis, I notice that you show 3 darcy feet, I assume that's transmissibility, between tanks, what we are now calling 3 and 4, the expansion area and the central Canada Ojitos Unit, as you refer to it.

A Yes.

Q Can you explain the lack of response after the C-34 well was fraced, lack of response in the B-29 and B-32 if there is 3 darcy foot transmissibility?

A I disagree totally with that interpretation of the interference test. There was clearly response of exactly the size you would expect with the kind of permeability (unclear).

Q Thank you. Nothing further, Mr. Chairman.

MR. LEMAY: Additional questions? If not, Mr. Kellahin.

MR. KELLAHIN: Thank you.

MR. LEMAY: You may proceed.

REDIRECT EXAMINATION

BY MR. KELLAHIN:

Q Dr. Lee, I want to direct your attention to the general discussion we've had with Mr. Douglass on Mr. Roe's testimony from March of '87 and relate it back to Exhibit Number Twenty.

The available pressure information from the unit shows that in 1971 we have a pressure measurement in the C-34 Well.

A Yes, sir.

Q And it's not again until 1987 that we have a measured pressure in the C-34 Well.

A Yes, sir.

Q There is nothing on that well between those two periods, is there, sir?

A That's correct.

Q And we have a period of in excess of 20 years.

A Yes, sir.

Q And if Mr. Hueni takes those two data points, plots them as he does with this dashed line, that is going to represent a pressure decline for the unit based upon those two points of about 11 pounds a year, is it not?

A Yes, sir.

Q Now, Mr. Roe has done the same thing.

He has taken those same two bits of information about the unit, plotted those, made the calculation, he will also show a rate of decline in the unit of about 11 pounds a year, will he not?

A Yes, sir.

Q If you'll turn to Exhibit Number One to your display on page 3, in using your material balance verifications, you have told us as a result of gas over-injection in the unit we can have a pressure curve for the unit that honors the data point in the C-34 Well both in 1971, as well as in 1987, and have a hump in the curve.

A Yes, sir, I tried to state that earlier in response to a question, but again, yes, with the path in between it could be anything and therefore let's develop a model of the reservoir which seems to explain what's going on and we'll see what that path is likely to be, but it certainly could go up in between.

Q So Mr. Roe and Mr. Hueni can say that we have pressure decline in the unit of 11 pounds a year using those as the data points and not be inconsistent with the conclusions and analyses that you've made.

A Yes, in fact, the context of the transcript that I saw sort of indicated that that was the kind of calculation that was made.

Q Let's assume that intermediate period

ends in 1986, somewhere about then, I'll ask you to pick the point, but when we look on page 3 can we take that intermediate point and simply disregard it, examine the later time on your display on page 3 and draw any conclusions about the presence or absence of the barrier?

A I think we have to take everything into account. What has happened historically, you know, that would be part of our observation points today.

Q Can we ignore the early time, the intermediate time, and take the last portion of the display for the last couple of years and draw any conclusions about that with regards to the barrier?

A Oh, I'm sorry. With all the pressures declining, despite a lot of injection, I think that indicates that there is significant pressure communication with all the pressure declining in step. To me that would again indicate lack of a barrier.

Q So we can just ignore all the rest of this until we get to the last 20 percent of the display and you can still analyze it and show that there is no barrier.

A I think so. In fact, as we did earlier today, you can take a 6-month period (unclear) the barrier.

Q Let's talk about the sponge and how we can squeeze that sponge.

If you'll turn to page 17 of your

report, Exhibit Number One, Commissioner Humphries says it was hard for him to disregard Mr. Hueni when Mr. Hueni says we need to get a large pressure differential in order to get that matrix to produce.

Can we take that 6-section area on the Proponents Exhibit Number Five, we have -- we have a 6-section area that's the sponge, do we not?

A Yes.

Q And the field observations in that 6-section area contain 8 wells.

A Contains more than 8 wells here, I think.

Q Let's assume that we look at 8 wells --

A All right.

Q -- within the 6-section area. From initial reservoir pressure down to present times we have squeezed that sponge by 1000 pounds, have we not?

A We've provided a 1000 pound driving force to get the oil out of the matrix, to squeeze the sponge.

Q And what is happening with those 8 best wells within that area?

A Well, they're not the best wells in the area. They were 8 wells that were formerly quite good wells on the average and what's happening to them is that they're dying.

Q We can't squeeze that sponge hard enough with 1000 pounds below initial reservoir conditions to get the oil out of the matrix if it was ever there.

A It sure doesn't appear to be coming.

Q Is there any other way to take a field observation test and show that you can't squeeze the sponge any harder?

A I think that's the most direct evidence probably possible. The rest is based a lot on interpretation but this is pretty direct.

Q Okay. Taking those rates up to the high allowable and squeezing the sponge at the high rates is not going to get us oil out of there, is it?

A Right.

Q But your fundamental point is the oil is not there anyway.

A Right, that's my point.

Q Thank you.

MR. LEMAY: Thank you, Mr. Kellahin.

Other than starting another witness I --

MR. DOUGLASS: Mr. Chairman.

MR. LEMAY: Yes, sir.

MR. DOUGLASS: I have some additional questions, if I may.

MR. LEMAY: Fine, excuse me.

RECROSS EXAMINATION

BY MR. DOUGLASS:

Q Dr. Lee, Mr. Kellahin asked you if Mr. Roe had taken that pressure in the C-34 and then calculated it from the original pressure he'd gotten about this 11-pound pressure drop. Do you recall that?

A Yes, sir.

Q All right, sir, are you aware that the pressure measurement in the C-34 was made in November of 1987?

A I'm really just not familiar with it.

Q Well, assume with me that it was made in November of 1987. In fact, I believe you can look at Mr. -- Mr. Hueni's Exhibit Twenty and see that the pressure is shown right at the -- essentially at the end of the year, isn't it?

A Yes, sir.

Q And I assume you're aware that Mr. Roe testified in March of 1987 about the pressure decline.

A I don't remember that testimony.

Q Our Exhibit Fifty-one?

A Oh.

Q So there wouldn't have been any way that he could have taken the C-34 pressure in November of '87 and calculated an 11 pound pressure drop and testified about it in March of '87, could he?

A Couldn't have been based on that particular pressure measurement.

Q Let's look at the 8 wells that you're talking about there with Mr. Kellahin. Did you have a graph of their production and gas/oil ratio on page 19?

A Yes, sir.

Q After June of -- well, let me ask you, is the -- is January of 8 -- is June of '87 or July of '87 right over the 1987 there, in other words the year period goes to your slashes to slashes, is that correct?

A Yes, sir, that's correct.

Q Does it appear that each time the oil production rate leveled out or went up that the gas/oil ratio went down with reference to those 8 wells?

A That's true on a short term basis, but we still got the obvious trend.

Q It's true on a short term basis with reference to four separate events on your chart here.

A Yes, sir.

Q The reasonable explanation of that could be oil coming through the matrix, is that right?

A That is one explanation. We believe we have others.

Q And let me ask you about -- don't you show that the total daily oil production from those 8 wells as you describe them, about to die, is about 60 percent or in excess of 60 percent of the total production coming from the pressure maintenance area currently?

A But the pressure -- well, the answer is yes.

MR. DOUGLASS: Pass the witness.

MR. LEMAY: Additional questions? Mr. Kellahin.

REDIRECT EXAMINATION

BY MR. KELLAHIN:

Q Your explanation to the last question?

A Well, the -- in the case of the pressure maintenance area, of course, the -- we have gravity drainage of oil down to wells in the expansion area. I think the evidence is very clear, there seems very clear pressure support. Those wells are not about to die. We've -- we've moved past some of the wells in the current pressure maintenance area where the gas/oil contact was clearly gravity drainage and continuing movement of oil down structure.

MR. KELLAHIN: Nothing further.

QUESTIONS BY MR. LEMAY:

Q I have a question, Dr. Lee.

A Yes.

Q In analyzing on page 19, just a straight production plot in a fractured reservoir, with matrix contribution, is it common to see that curve at a point in time where the fracture system is depleted to turn on a different angle? In other words, have a bend in that where the matrix starts contributing? Is there a characteristic curve to a dual porosity system well?

A Characteristic curve but it occurs in heterogeneous reservoirs; occurs in layered reservoirs, for example, where we've got -- we deplete one layer of higher permeability and there's another lower permeability layer, and it's harder for that oil or gas to come out but, you know, it comes once there's a big enough pressure difference from the other layer. It's generally characteristic of heterogeneous systems, one of which is a dual porosity system.

Q But as far as a fingerprint for a dual porosity system decline curve or a single porosity, fracture only system, there is not any differentiation in the production versus time plot?

A I don't know. I know there are a lot of, you know, certainly not this leveling out. That's pretty characteristic of just an awful lot of formations all over the world. They will decline, say, exponentially for awhile but not forever. They will eventually level out due to the lower permeability parts of the system whether it be layers or a matrix in a dual porosity system, or just generally lower permeability rock; more common than not.

MR. LEMAY: Additional questions?

If not, the witness may be excused.

Thank you, Dr. Lee.

Rather than start another witness I think it's best we adjourn and we'll reconvene tomorrow morning at 8:30.

(Hearing adjourned.)

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 512 through 749, 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