

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 CASES  
in Cases Nos. 7980, 8946, 8950, 7980, 8946,  
9111 and 9412. 8950, 9111,  
9412.

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

TRANSCRIPT OF HEARING

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1 MR. LEMAY: The hearing will  
2 come to order.

3 So we shall resume with Mr.  
4 Douglass.

5 MR. DOUGLASS: Thank you, Mr.  
6 Chairman.

7 Call Dr. Charles Kohlhaas.

8  
9 CHARLES A. KOHLHAAS,  
10 being called as a witness and being duly sworn upon his  
11 oath, testified as follows, to-wit:

12  
13 DIRECT EXAMINATION

14 BY MR. DOUGLASS:

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

17 A Charles Kohlhaas.

18 Q What's your occupation?

19 A I'm a petroleum engineering consultant.

20 Q Where do you reside?

21 A In Golden, Colorado.

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

24 A Yes, in both cases.

25 Q Yes, all right. Have you testified be-

1 fore the New Mexico Commission before?

2 A Yes.

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

5 A Oh, I think about thirty years ago.

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

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

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

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

23 I have consulted in various parts of the  
24 world and I formed and managed an independent oil company  
25 for a short time, which I sold about a year and a half ago,



1 and since then I've been consulting full time.

2 Q Are you a Registered Professional En-  
3 gineer in any states?

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

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

8 A Yes, sir. I worked with fractured re-  
9 servoirs in California, Texas Gulf Coast Area, west Texas,  
10 southeast New Mexico, northwest New Mexico, Canada, Wyom-  
11 ing, Colorado, the North Sea, the Middle East.

12 Q Have you made a study of the Gavilan -  
13 West Puerto Chiquito Field area and prepared or had pre-  
14 pared under your supervision, certain exhibits and testi-  
15 mony for presentation here today?

16 A Yes, sir.

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

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

21 MR. DOUGLASS: Mr. Chairman, I  
22 believe yesterday we had a reversal of exhibits. I was  
23 glad to report that Dr. Kohlhaas is well today, but he had  
24 a bout of food poisoning the night before so we reversed  
25 our witnesses as far as presentation is concerned but if

1 you'll just shift those exhibits back we'll start with  
2 Exhibit Thirty-nine and I believe his exhibits will be  
3 numbered Thirty-nine through Forty-three.

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

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

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

12 Q We have identified as Exhibit Thirty-  
13 nine a map entitled Well to Well Interference Test Loca-  
14 tions.

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

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

24 Interference tests can be two or more  
25 wells, one of which will be designated as the source well

1 and the others are designated observation wells.

2           The common technique is to put a pres-  
3 sure gauge in the observation wells and measure the pres-  
4 sure during some event in the source well. Now those  
5 events can be variable. They're quite commonly the opening  
6 and closing, starting and stopping of production in those  
7 wells.

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

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

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

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

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

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

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

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

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

14                  A           Yes, sir.

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

17                  A           No, sir.

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

21                               MR. LEMAY: Fine. Mr. Doug-  
22 lass, I have a map different than you show on the board. I  
23 don't show the red lines.

24                               MR. DOUGLASS; We're going to  
25 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 --

1 on Exhibit Thirty-nine here?

2 A Both of those area in the Gavilan Mancos  
3 area.

4 Q All right. F-7 --

5 A Expansion area, excuse me.

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

7 A J-6, yes.

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

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

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

17 A Yes.

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

22 A Yes, sir.

23 Q Anything else -- well, let me ask you,  
24 what -- explain to us that -- that first chart there, what  
25 is shows on Exhibit Forty, that is the frac in the F-7 and

1 the response in the J-6, if any.

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

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

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

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

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

16 A Shut in.

17 Q With a pressure bomb in the well?

18 A Yes, sir.

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

21 A Yes, sir, and it's quite typical. A  
22 fracture treatment is a high pressure, high rate, high  
23 volume injection of fluids into the well for a short period  
24 of time and normally the fracture treatments out in this --  
25 in this area last only a few hours and you can see that the

1 pressure spike here is quite characteristic. It's what  
2 you'd expect from that type of a pressure pulse going  
3 through the reservoir. It goes up abruptly and it comes  
4 down. The slower bleed-off is caused by the fact that the  
5 well remained shut-in after the fracture treatment and the  
6 pressure must disperse throughout the matrix and the frac-  
7 ture system of the reservoir.

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

11 Q Anything else you want to add with re-  
12 ference to Exhibit Forty?

13 A No, sir.

14 MR. DOUGLASS: Offer Exhibit  
15 Forty?

16 MR. LEMAY Accepted without  
17 objection.

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

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

23 Q Excuse me. this should be a foldout  
24 sheet larger exhibit. Exhibit Forty was 12 pages long and  
25 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 re-produced 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

1 well.

2 A That's correct.

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

5 A Both of these indicate good communica-  
6 tion between these pairs of wells. We have good pressure  
7 communication and interference between them. There's no  
8 doubt that these wells are in communication.

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

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

15 The -- we examined those pressure meas-  
16 urements. We see that there is no response to any event in  
17 another well.

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

20 A All right. In the upper right panel we  
21 have the pressures measured in the B-29 Well during a frac-  
22 ture treatment of the C-34.

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

25 A Right.

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

3                   A                   Yes. The C-34 was fractured at the time  
4 the arrow was shown there and it's obvious there's no re-  
5 sponse.

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

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

11 Q Should the red tape be removed with re-  
12 ference to those two wells?

13 A Yes, sir.

14 Q What's the next chart down?

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

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

20 A Yes, sir.

21 Q This one even closer, I believe, --

22 A Right.

23 Q -- the C-34.

24 A Yes.

25 Q In other words, the B-29 had its pres-

1 sure -- it was shut-in with a bottom hole pressure bomb in  
2 it --

3 A Right.

4 Q -- and the B-32 was shut in with a bot-  
5 tom hole pressure bomb in it.

6 A Right.

7 Q And the C-34 Well was fraced.

8 A Right.

9 Q And the C-34 is across the barrier.

10 A Right.

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

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

15 Q Should that red line be removed?

16 A Yes, sir.

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

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

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

25 A Yes, sir.

1 Q No interference, is that correct?

2 A No interference, right.

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

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

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

10 A Right.

11 Q Please proceed.

12 A And again there's no response, no pres-  
13 sure indication here of the fracture treatment, no inter-  
14 ference and no communication.

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

17 A Yes, sir.

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

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

25 MR. DOUGLASS: Offer Exhibit

1 Forty-one.

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

4 Q Now, in analyzing pressures can you  
5 obtain data and information that can tell you where bound-  
6 aries or barriers are, not necessarily exactly where they  
7 are, but whether they are in the reservoir or not?

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

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

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

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

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

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

7                   In the center upper panel is a repro-  
8       duction from his original paper. This particular repro-  
9       duction is in the SPE Monograph No. 1, published in 1967,  
10      and it shows his analysis, his original analysis, his ori-  
11      ginal paper of the response of a pressure build-up to a  
12      barrier, and this plot shows that there will be a curvature  
13      of the build-up between an early period of time and a late  
14      period of time. The early period of time will be straight  
15      before the curvature intrudes. After the curvature dies  
16      out there will be a later straight period on the Horner  
17      plot and that those two periods can be connected with two  
18      straight lines. The slope change of those -- the slope  
19      ratio of those two straight lines is to in the ideal case  
20      of the vertical, straight, infinite barrier. In nature --

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

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

1 1.5 to about 2.5.

2 Q What else have you shown on this exhi-  
3 bit, Mr. Kohlhaas?

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

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

14 Q What about the panel below the Horner  
15 plot here?

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

22 Earlougher makes the point here that a  
23 slope change is not to -- it can be used to interpret the  
24 intersection or the curvature of the barrier and he makes  
25 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.

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

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

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

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

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

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

20 A Yes, sir.

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

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

25 Q All right, what have you found with re-

1       ference to the slope change?

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

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

13              In   this   case   the   build-up   was   not   per-  
14      turbed   by   the   response   to   the   fracture   treatment   and   so   I  
15      went   ahead   and   interpreted   them   as   area   build-up   tests   and  
16      we   can   see   the   slope   change   here   in   each   case   follows   the  
17      ratio   that   we   normally   observe   for   varying   responses,   be-  
18      tween   1.5   and   2,   and   we   drew   the   --

19              Q              You   said   1.5   and   2.

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

25              Q              All   right,   sir,   with   your   first   upper

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

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

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

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

11 A Yes, sir.

12 Q And one of them calculated to show a  
13 distance to a barrier of about 2020 feet and the other one  
14 1990 feet, is that correct?

15 A Right. Right.

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

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

21 Q Approximately half a mile, is that  
22 right?

23 A Yes.

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

1                   A           That's a test of the A-20 Well and the  
2 distance to the barrier in that well was calculated to be  
3 320 feet.

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

8                   A           Yes, sir.

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

13                  A           As far as I know.

14                  Q           What's your conclusion then with refer-  
15 ence to these four pressure tests measured in three of the  
16 wells that are near the barrier?

17                  A           Well, the lack of response to the frac-  
18 ture treatment during the interference part of this testing  
19 proves that there's a barrier there and the analysis of  
20 these build-ups confirms that barrier, and not only allows  
21 us to confirm the presence of the barrier but to calculate  
22 the difference the distance to it.

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

25                               MR. LEMAY: Forty-three admit-

ted without objection.

MR. DOUGLASS: Pass the witness.

MR. LEMAY: Mr. Pearce?

Thank you, Mr. Chairman.

MR. LOPEZ: No, Mr. Chairman.

questions of the witness?

MR. LEMAY: You first, Mr. Carr?

CROSS EXAMINATION

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.

A I think it was about a pound and a half,

1 two pounds.

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

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

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

10 A Yes.

11 Q Would you normally expect to see a dif-  
12 ference if the wells were twice as far apart?

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

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

22 A Rule of thumb for what?

23 Q I mean would it be half -- if you go  
24 twice as far do you expect a change in the response, say, a  
25 50 percent change, or is there, in your profession is there

1 any standard that you allude to?

2 A If the reservoir characteristics were  
3 exactly the same?

4 Q Yes, sir.

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

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

10 A It would depend on the reservoir.

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

14 A Yes.

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

17 A Well, that's what a barrier is. A bar-  
18 rier goes from some finite value on one side to zero on the  
19 other.

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

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

24 Q But could it be less than zero?

25 A No.



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

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

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

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

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

10 A Excuse me.

11 MR. DOUGLASS: -- before you  
12 start.

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

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

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

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

24 Q I understand, but if you just look at  
25 the pressure test and forget the others just for the

1 purpose of this question, that along doesn't establish a  
2 barrier, just a change in permeability.

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

5 MR. CARR: That's all.

6 MR. LEMAY: Mr. Kellahin.

7 MR. KELLAHIN: Thank you, Mr.  
8 Chairman.

9

10 CROSS EXAMINATION

11 BY MR. KELLAHIN:

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

16 A I was provided the exhibits from the  
17 previous hearings?

18 Q Were you provided the transcripts of  
19 those exhibits?

20 A Yes, sir.

21 Q When you talk about the previous exhi-  
22 bits from the previous hearings what specific exhibits were  
23 you provided from what particular hearing?

24 A I was provided the exhibits from the  
25 March, 1988, and some from the -- it was in 1987, I don't

1 remember the date, April, 1987?

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

5 A Yes.

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

9 A Yes.

10 Q Were you provided with any of his tran-  
11 scripts, testimony and exhibits from any other of these  
12 hearings with regards to this subject?

13 A No, sir.

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

17 A Yes.

18 Q Thank you.

19 MR. LEMAY: Additional ques-  
20 tions of the witness?

21 He may be excused.

22 MR. DOUGLASS: Call Mr.  
23 Powell.

24 A Thank you.

25

1  
2 MAX F. POWELL.

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

5  
6 DIRECT EXAMINATION

7 BY MR. DOUGLASS:

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

10 A Max F. Powell.

11 Q What's your occupation, Mr. Powell?

12 A I am a consulting petroleum engineer.

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

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

16 Q Or an engineer?

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

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

21 A I do.

22 Q From where and when?

23 A From Texas A & M in June of 1949.

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

1           A           Following graduation from Texas A & M I  
2 was first employed by what was then called Halliburton Oil  
3 Well Cementing Company but I had nothing to do with cement.  
4 I was in the electrical well surveying division of Halli-  
5 burton and in that capacity assisted in running those kind  
6 of surveys in open hole well bores including, but not lim-  
7 ited to electric logs, temperature surveys, caliper sur-  
8 veys, taking sidewall cores, and things of that nature.

9                   I left Halliburton effective November  
10 30, 1949, and accepted a position with the Railroad Commis-  
11 sion of Texas, which is the oil and gas regulatory agency  
12 for the State of Texas, in its District IX office, located  
13 in Wichita Falls, Texas.

14                   For approximately two years I was invol-  
15 ved primarily with field testing of both oil and gas wells  
16 and some reservoir evaluation work.

17                   On October 15, 1951, I was transferred  
18 by the Railroad Commission to its headquarters office  
19 located in Austin, Texas, and there I was assigned the job  
20 function of Technical Hearings Examiner. In that capacity  
21 I presided over approximately 800 technical hearings for  
22 the next one and one-half years and following the eviden-  
23 tiary phase of those hearings I reduced the testimony and  
24 evidence to a document referred to in those days as a  
25 Memorandum to the Commission. I recited what I felt to be

1 the prevailing testimony and evidence. I made findings of  
2 fact and recommendations to the three Commissioners re-  
3 garding ultimate disposition of the issues.

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

6 A No, they did not.

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

9 A No, that was my function.

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

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

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

25 In addition, the Commissioners had other

1 divisions, such as the Motor Transportation Division, the  
2 Railroad Division, the Rate Division, the Liquified Petro-  
3 leum Gas Division, and now for the last considerable number  
4 of years, the Surface Mining Division, and all of those  
5 divisions have on-going issues before them that the Commis-  
6 sion takes testimony and evidence through the hearing pro-  
7 cedure.

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

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

18 We did, and I did, appear on an infre-  
19 quest basis in both State and District Federal Courts.

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

25 In June of 1957, one year later, I ac-

1 cepted employment by what was then my better client and  
2 generated approximately 50 percent of my prior year's reve-  
3 nue, by the name of Russell Maguire, M-A-G-U-I-R-E, who was  
4 an individual who lived in Greenwich, Connecticut. He had  
5 offices in New York City, but the oil and gas properties  
6 that he was engaged in were operated out of Dallas, Texas.

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

16 Following the establishment of commer-  
17 cial production, it was within my responsibility to market  
18 all oil and gas or condensate that would have been pro-  
19 duced. Oil and condensate I always marketed under verbal  
20 agreements. That was never the case with respect to gas,  
21 even casinghead gas. It was always done under contract and  
22 predominately long term contracts, which I negotiated and  
23 reduced to writing.

24 My job function, or job title, rather,  
25 was subsequently changed, perhaps in the early 1960's,



1 about 1961 or 2, to Production Manager. It was -- it was  
2 for cosmetic purposes only; it had nothing to do with my  
3 job responsibilities; they remained the same, but by that  
4 time I did have the beginnings of a staff. I had two full  
5 time engineers, one who helped me with respect to the daily  
6 drilling activity and most often we had between 10 and 15  
7 drilling rigs operating around the country and that was a  
8 pretty major involvement.

9 I had another engineer who helped me  
10 with the secondary recovery projects that had been initi-  
11 ated and by that I mean that when I joined Russell McGuire,  
12 he had a large number of properties scattered over predomi-  
13 nately six southwestern states, being Texas, New Mexico,  
14 Kansas, Oklahoma, Louisiana, and Mississippi.

15 There were a large number of wells and  
16 field areas that were in need of secondary recovery appli-  
17 cation. A lot of those properties were studied, primarily  
18 by me in the early years, with the result that I put to-  
19 gether and operated 23 unitized secondary recovery projects  
20 ranging from the smallest one, a 15-well waterflood opera-  
21 tion at a Gunzite (sic) sand depth of 600 feet, to a high  
22 pressure gas cycling project involving surface pressures of  
23 approximately 8000 pounds per square inch at a depth of  
24 10,000 feet.

25 Q Approximately how many wells were invol-

1       ved in your operations with Mr. McQuire?

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

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

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

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

20                              I was prevailed and encouraged by the  
21      Railroad Commission, two of the Commissioners, the Chief  
22      Engineer, and the Chief Technical Hearings Officer, to re-  
23      join the staff of the Railroad Commission as a Senior Staff  
24      Engineer, which I did beginning on November 5, 1970. I was  
25      in that capacity where I again was a presiding Hearing

1 Examiner. I did that work for four years, until September  
2 1, 1974.

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

12 That hearing was convened in April of  
13 1970; it was in continuous session for six months, five  
14 working days per week. It generated 15,000 pages of tran-  
15 script; over 1400 technical exhibits; it was a major under-  
16 taking and consumed a great deal of my time for the first  
17 year and a half with the Railroad Commission.

18 Q You said April of '70.

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

23 I left the -- resigned my position with  
24 the Railroad Commission effective September 1, 1974, and  
25 re- opened offices in Austin, Texas, as a consulting

1 petroleum engineer and I have remained in that practice  
2 continuously since that time.

3 Q Are you a Registered Professional En-  
4 gineer?

5 A I am.

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

8 A Yes, I have.

9 Q How many would you approximately esti-  
10 mate you were involved in?

11 A I have no actual count but considering  
12 the involvement both as an Examiner on two different per-  
13 iods of time, 1951 to 1953, and from 1970 to '74, and then  
14 then the consulting years from 1953 to 1957, and again from  
15 1974 to the present date, I would -- I would believe that  
16 the number of regulatory hearings in which I've been invol-  
17 ved in one capacity or the other will have been perhaps at  
18 least 3-to-4000, and perhaps as many as 6-to-8000.

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

22 A No.

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

25 A The standard for determining what is a

1 field in Texas is that rules are adopted for a field  
2 identity, which addresses a common reservoir or a common  
3 source of supply regardless of the geographic boundaries.  
4 For example, that field identity and rule adoption might  
5 very well go with the discovery well, and most often does,  
6 and as development occurs and additional wells are drilled,  
7 the rules follow wherever that common source of supply  
8 goes.

9 Q What is you have three or four separate  
10 reservoirs in the same area or same wellbore where wells  
11 are completed in separate reservoirs? Are all -- are they  
12 classified all in the same field, or is that, say, four  
13 separate fields as far as the Railroad Commission is con-  
14 cerned?

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

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

23 A Yes, it does.

24 Q Would you say it's one of the more fre-  
25 quent fights and occurs as far as the Railroad Commission

1 is concerned, or one of its more frequent issues that the  
2 Commission has to determine?

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

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

9 MR. LEMAY: His qualifications  
10 are acceptable.

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

14 A Yes.

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

18 A Yes, I have.

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

24 Exhibit Forty-four is a tabulation en-  
25 titled Statistical Analysis, 1968 & May, 1988 Oil Proration

1 Schedules.

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

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

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

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

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

25 There are others with much larger

1 reserves but not area.

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

4 A On Exhibit Forty-four, going to the  
5 bottom of the page and the underscoring August and Decem-  
6 ber, 1968 Oil Proration Schedules, I have set out in tabu-  
7 lar format, looking to the lower righthand corner under  
8 Combined Districts, I won't refer to the individual dis-  
9 trict separately, I show that in August and December, 1968,  
10 the Railroad Commission had on its oil proration schedules  
11 a combined District total of 3,659 oil wells.

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

22 Q Mr. Powell, you took two different pro-  
23 ration schedules there. Is that because of the District  
24 7-C and the District 08 schedules were printed at different  
25



1 times as far as the Railroad Commission is concerned?

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

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

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

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

18 Q Well, the current situation being de-  
19 scribed as the data contained on the Railroad Commission's  
20 May, 1988, Oil Proration Schedule for both District 7-C and  
21 08, I won't go through all of the lines of data shown with  
22 reasonably good detail for the two districts, except to  
23 state that the total number of wells during the intervening  
24 20-year period from 1968 to May, 1988, had increased from  
25 3,659 wells to 8,171 wells, which is an increase of than

1 100 percent in total number of wells.

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

4 A During that same interval of time the  
5 number of wells on leases or units that were involved in  
6 secondary recovery projects will have declined from a  
7 20-year earlier period of 2,031 to a May, 1988 numerical  
8 value of 1,211, which is a substantial decline in wells  
9 that were involved in secondary recovery even though the  
10 total number of wells in the field, and thus the candi-  
11 dates, or potential candidates for secondary recovery, had  
12 more than doubled during that time.

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

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

18 Q How many acres are not in secondary in-  
19 jection programs (unclear)?

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

24 Q I see on this schedule that there  
25 appears to be one gas injection well. Did you investigate

1 to see if there is a gas injection well or if that was a  
2 gas injection well?

3 A Yes, I have.

4 Q And what did you determine?

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

8 I had reason to suspect that there was  
9 no on-going gas injection well in District 08 in 1988 and I  
10 looked to it further and I found that that well was operat-  
11 ed by a brine sales company. It is a commercial salt water  
12 haulers company and the well number on the proration sched-  
13 ule had a 1-G, intending to represent gas injection, where-  
14 as it should have said 1-D, which is a salt water disposal  
15 well. I had confirmed that that is an error upon the Com-  
16 mission schedule but I didn't want to change it on my Ex-  
17 hibit Forty-four because it has not yet been printed and  
18 the correction made by the Railroad Commission.

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

23 A Yes, that is correct.

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



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

8                   Between the two bars I have shown the  
9 difference in the height of two colors. The uppermost one  
10 has a value of 4,512 and that is intended to show and does  
11 show that the total number of wells during the intervening  
12 20-year period increased by a numeric value of 4,512 total  
13 wells, while concurrently the number of wells that were on  
14 leases or units participating in on-going secondary recov-  
15 ery operations by injection of water had declined by 820  
16 wells to a new value in 1988 of 1,211, which is very little  
17 more than 1 out of every 8.

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

22               A           Yes, that is correct.

23               Q           Were there any major pressure mainte-  
24 nance or secondary recovery projects installed during that  
25 20-year period?

1 A There was not.

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

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

7 There is, however, authority resting  
8 with the Railroad Commission to approve voluntary unitiza-  
9 tion.

10 Q Has it been your experience that gener-  
11 ally in Texas that it's the operators seeing that it's  
12 economically feasible to carry on a secondary recovery or  
13 pressure maintenance project which brings about such a pro-  
14 ject?

15 A Yes.

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

18 A Well, not much between 1968 and 1973,  
19 but following the Arab oil embargo in I believe it was late  
20 1973, perhaps November, the price of oil did experience a  
21 general trend of increasing prices over that next, oh, per-  
22 haps 12-year period to when in 1985 and early 1986 it  
23 reached in some areas dollar values in the \$30-to-\$35 per  
24 barrel range.

25 Beginning in, perhaps, the first quarter

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

5 The prices started declining and got as  
6 low in some areas as \$10-to-\$12 per barrel. That has im-  
7 proved to some extent and the current level is in the  
8 \$15-to-\$17 per barrel range.

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

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

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

1 I do not see and I do not find that that  
2 happened in the Spraberry Field, which probably is -- con-  
3 tains, within the State of Texas, at least, if not a larger  
4 area, a tremendously large, unrecovered reserve that is not  
5 recoverable through primary operations, and to date has not  
6 been significantly added to the secondary recovery through  
7 the technique of waterflooding and no recovery has been ac-  
8 complished as a result of gas injection secondary recovery.

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

11 A Yes.

12 Q When and what was the occasion?

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

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

25 The issue in May of 1952 was whether a



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

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

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

17                   A           Yes. At least one other that -- that I  
18 recall very vividly. It was in August of 1952, and I lis-  
19 tened carefully to Mr. Lincoln Elkins earlier to see  
20 whether or not his memory was -- or was relatively the same  
21 as mine. That was a hearing in August of '52, wherein At-  
22 lantic Richfield Company, following successful laboratory  
23 testing, sought authority from the Railroad Commission to  
24 conduct in the field secondary recovery testing through  
25 what to me at that time was a new word that -- the word was

1 "imbibition". I hadn't the slightest idea of what it meant  
2 but they soon clued me in at the hearing that it was a pro-  
3 cedure that had been developed in the laboratory where due  
4 to capillary pressure and attraction, water in the presence  
5 of that very tight matrix rock could be imbibed or, to use  
6 a word that I'm more familiar with, would be sucked into  
7 the pore interstices, and the thing that intrigued me, I  
8 guess, the most at that time was the testimony that as the  
9 water that was exposed to a fracture face, for example, and  
10 being imbibed or sucked into pore spaces, that the flow of  
11 oil would be counter-current to that; that there would be  
12 water moving in through the pore throats and simultaneously  
13 with that would be oil moving out, hopefully towards the  
14 fracture system that would be the transport vehicle to get  
15 the oil to a producing wellbore.

16 That -- that put a hickey on me because  
17 I wasn't too familiar with that and it seemed that that was  
18 a very unusual concept. I'd have to say that I embraced it  
19 with a great deal of enthusiasm because I knew at that time  
20 that the Spraberry field area, as it later came to be  
21 known, had tremendous quantities of oil that were not going  
22 to be recovered through primary operations. I had -- I  
23 remember with shock the exposure to the engineering estim-  
24 ates, such as Mr. Elkins', that the recovery from these  
25 tight rocks was going to be 7-1/2 percent and I thought

1 that was an extremely low value at the time and I was  
2 disturbed a little later that that was an optimistic  
3 estimate, that the recovery did not reach 7-1/2 percent of  
4 the original oil in place.

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

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

17 A It has a reputation, yes.

18 Q And what is it?

19 A Well, it is not one that it enjoys, and  
20 I suppose it endures it more than enjoys it. It is that  
21 the Spraberry rock is an extremely poor to extremely margi-  
22 nal candidate for secondary recovery operations utilizing  
23 water, and that's three kinds of water, fresh, brackish and  
24 salt water. It's very poor under that type of secondary  
25 recovery and the prospects of secondary through using gas

1 as an injection medium is nonexistent.

2 MR. DOUGLASS: Offer Exhibit  
3 Forty-five.

4 MR. LEMAY: Accepted into the  
5 record without objection.

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

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

14 It might be well to explain what the  
15 concept was and what I intended to investigate with the  
16 construction of what is now on Exhibit Forty-six. I wanted  
17 to investigate the -- the number of secondary recovery pro-  
18 jects that had reported to the Railroad Commission for its  
19 biennial secondary recovery booklet and investigation, what  
20 those projects had done with respect to injections and cer-  
21 tainly with respect to what they had recovered in the way  
22 of oil that the operator of each project himself attri-  
23 buted to his secondary recovery operations.

24 The last one of those published books by  
25 the Railroad Commission of Texas was the 1982 issue which

1 covered all projects for prior years up to and including  
2 December 31, 1987. Excuse me, I got that wrong, December  
3 31, 1981, the end of the calendar year just prior to publi-  
4 cation.

5 I found from that source that the quan-  
6 tity of oil that had been recovered by the various opera-  
7 tors of the units that are shown on Exhibit Forty-six in  
8 tabular form is included and set out on the third column  
9 from the lefthand side of Exhibit Forty-six, in the column  
10 that is entitled "Estimated Cumulative Oil Due to Secondary  
11 Recovery to 1-1-82 Barrels". The values that are in that  
12 column for each of the identified projects that are in both  
13 District 7-C and 08 came directly from the Railroad Commis-  
14 sion's secondary recovery book.

15 There has been no subsequent issue of  
16 that book by the Railroad Commission, I suppose due to  
17 budgetary restraints, since 1982, so to get any kind of  
18 estimate about what has happened with respect to these pro-  
19 jects since 1981, it was necessary to go to the Railroad  
20 Commission's annual production ledgers and I show those in  
21 the next six columns that are headed Annual Production -  
22 Barrels over six vertical columns that are also subheaded  
23 1982 through 1987.

24 Shown in those six columns for each of  
25 these various projects in District 7-C and 08 is 100 per-

1 cent of the production reported by each of those operators  
2 to the Railroad Commission. There is no differentiation  
3 there between primary production and secondary. I had no  
4 valid mechanism in which to break it down so the entire 100  
5 percent production is shown and with no distinction between  
6 secondary and primary.

7                   Those numbers were then totaled for each  
8 project in the next to last column on the righthand side of  
9 Exhibit Forty-six and then each District is totaled and  
10 finally below the two-district total there is a grand total  
11 which shows that through the end of 1987, or December 31,  
12 1987, the total cumulative oil that could be attributed to  
13 the -- as the result of secondary recovery operations in  
14 the Spraberry Trend Area Field is 66.4-million barrels.  
15 That, as I hopefully will have already stated, is perhaps  
16 overstated substantially for the periods, production  
17 periods, 1982 through 1987, but the 66.4 could be consider-  
18 ed as -- as a ballpark number or at least something that  
19 would -- would attest to the upper side of what the value  
20 is; it certainly cannot be more than that and in all prob-  
21 ability is substantially less.

22                   The last three lines of data at the bot-  
23 tom of Exhibit Forty-six show the total production of oil  
24 from the Spraberry Trend Area, and this would be inclusive  
25 of both primary and secondary for the two Railroad Commis-

1 sion Districts, and the grand total has been shown as the  
2 bottom-most or foremost line.

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

7 But for the three preceding years, be-  
8 ginning in 1984, the grand total was 19.2-million in; in  
9 1985, 20.6-million; and in 1986, 20.5-million; so for my  
10 purposes here of trying to get a reasonable quantification  
11 of full production and what percentage of that production  
12 has actually been secondary, I have assumed 20-million for  
13 the calendar year 1987 for the combined total Spraberry  
14 Field area.

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

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

23 A That -- that is correct and that repre-  
24 sents a substantial volume of oil less than I read in Mr.  
25 Weiss' preliminary report that the Spraberry had produced

1 about 1-billion barrels of oil, 750-million of which could  
2 be attributed to secondary recovery. I find that that is  
3 not the case; that the total production, both primary and  
4 secondary, is about 570-million barrels, a little more than  
5 half of the 1-billion estimate.

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

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

23 Q Assuming 11.6 percent additional recov-  
24 ery from the field area by instituting the secondary pres-  
25 sure maintenance projects, in other words would that be



1 considered economic just in normal parameters concerned?

2 A Well, I suppose if one were to analyze  
3 whether it's economic would need to look to an individual  
4 project with respect to recovery costs, and that's a lit-  
5 tle general for me, but I can conclude that in my exper-  
6 ience I never would have considered anything where I anti-  
7 cipated getting 10 or 11 percent of the -- of additional  
8 recovery; that's not, in my view, a viable prospect that I  
9 would recommend to my company or client to engage in.

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

13 A I have.

14 Q And we'd like to have identified as Pro-  
15 ponents Exhibit Forty-seven a tabulation entitled Gas In-  
16 jection Projects Spraberry Trend Area Field, Railroad Com-  
17 mission Districts 7-C and 08.

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

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

23 MR. DOUGLASS: Thank you, sir.

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

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

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

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

17                      There was no subsequent reporting of  
18   that activity that I could locate in Railroad Commission  
19   files, but I do have the documents on the Railroad Commis-  
20   sion's 1968 Oil Proration Schedule where injection wells,  
21   and wells of every kind, whether they are shut-in, produc-  
22   ing, have an exception to a plugging rule, or they are cur-  
23   rently involved in water injection, gas injection, or salt  
24   water disposal activities, all of those categories are re-  
25   ported and shown on the Commission's proration schedule.

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

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

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

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

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

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

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

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

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

22 The last one listed is in District 08,  
23 where Mobil Producing Texas and New Mexico, Inc., under  
24 date of February -- under date of February, 1970, engaged  
25 in the injection of gas and it was more particularly defin-

1 ed as plant residue gas; I would often describe that as  
2 plant tailgate gas; injected gas into the -- its Preston  
3 Spraberry Unit, which comprised a total of 17,038 acres.

4 The injection was initiated in February, 1970, and was per-  
5 manently discontinued in May of 1970, three months later,  
6 and Mobil evaluated the effectiveness of that gas injection  
7 short-lived operation as not effective and I ascribed the  
8 word "failure" to it, but the word "failure" addresses more  
9 the applicability of gas injection as a vehicle to improve  
10 secondary recovery in a fractured environment such as the  
11 Spraberry rock in the Spraberry Trend Area Field.

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

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

25 They not only did not achieve that

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

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

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

19 A I am.

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

23 A I have.

24 Q And is the first one of those dated June  
25 30, '87, Figure 2, page 23 out of that report, and I'll

1 identify it as Exhibit Forty-eight.

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

5 MR. LEMAY: Forty-seven is ac-  
6 cepted without objection.

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

10 A What is basically shown is an isobaric  
11 map or that is a map under which an analyst, such as my-  
12 self, will put values of pressure by symbols representing  
13 wellbores and then connect points of equal pressure and  
14 that then results in a graphic representation of not only  
15 the pressure or value for each of the wells, but the pres-  
16 sure distribution within the source of supply.

17 This is a very commonly used procedure  
18 by engineers and I think even the geologists sometimes en-  
19 gage in this.

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

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

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

14 Before doing that I did discover that  
15 there were three pages of pressure data entered on maps,  
16 none of them contoured, and that the wellbores on the maps  
17 were not consistent throughout. For example, there were  
18 some wells on one page and some not on the next page, or  
19 the third, so there was not commonality of wellbores inves-  
20 tigated for each of the three pressure survey periods. I  
21 attempted to cure that by putting on each of the maps that  
22 Mr. Weiss addressed each of the wellbores whether or not it  
23 was surveyed on that particular map survey date.

24 I found that from looking to either pre-  
25 ceding pressure surveys or succeeding pressure surveys,



1 that I could make reasonably accurate estimates of what the  
2 pressure would have been in that given well that was not on  
3 the map had it been put on the map. So I put it on and I  
4 did estimate the pressure based on either prior or succeed-  
5 ing pressure results of nearby wells and the well itself.

6 So by way of explanation, the wellbores  
7 that are in sort of freehand, with freehand entries for  
8 pressure value followed by the letter capital E and the  
9 well number below the wellbore symbol, those represent  
10 wellbores that I have put on one or more of these maps from  
11 one or more of the maps that are in the group. The idea  
12 was to have on each map all of the wellbores that had had  
13 pressures taken during any one or more of the three pres-  
14 sure surveys and when it had a value, rely on that; when it  
15 didn't have a value, look to before and after and estimate  
16 the pressure in that well based on the intermediate acti-  
17 vity.

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

25 I see where the westernmost wells appear

1 to be the High Adventure No. 1 looks like in Section 8, and  
2 appear to be to the south of that the Loddy down in Section  
3 20, and I'm pointing to those wells. Those wells are on  
4 the far west side of the Gavilan area, is that correct?

5 A That is correct.

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

9 A Yes, sir.

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

14 A Yes, I believe that's correct.

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

20 A Yes, that is correct, even though Exhi-  
21 bit Forty-eight is on an 8-1/2 by 11 size piece of paper,  
22 the geographic area considered by that map is -- is exten-  
23 sive, very large.

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

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

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

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

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

19                       Those were taken, as a photocopy of Mr.  
20 Weiss' work from his exhibit on page 23, Figure No. 2 . I  
21 did add approximately six wellbores, I think it's exactly  
22 six wellbores, that will appear on one or two of the suc-  
23 cessive investigations by Mr. Weiss and I estimated those  
24 pressures, and each of the pressures is identified and each  
25 is followed by the capital letter E to indicate that that

1 is my estimate and not that of Mr. Weiss.

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

14 I cannot contour the pressure values  
15 which were in the eastern 1/3rd of Exhibit Forty-eight in a  
16 common, ordinary means of contouring technique and grade  
17 those contours into the values that are in the Gavilan and  
18 the expansion area to the west. I find that in the eastern  
19 1/3rd, which is, I believe, the pressure maintenance area,  
20 that the pressures are obviously substantially higher going  
21 from a maximum of 1504 in the K-13 Well to a minimum of  
22 1402, and that is my estimate based on subsequent pressures  
23 in Well No. E-10.

24 That then requires the construction of  
25 the isobar lines or contours in a north/south orientation

1 and it -- the pressure decrease is a little more than 100  
2 psi per inch and that's a measured inch, or scale inch, not  
3 so many thousand feet, but an inch on Exhibit Forty-eight  
4 on the east part. I could not carry that same kind of  
5 pressure difference and decreasing pressure into the west-  
6 ern portion, so I contoured the western portion and found  
7 that the behavior of the pressure isobars was dramatically  
8 different, just amazingly different, than what I was seeing  
9 on the east side. seeing on the east side. It is not what  
10 I would expect nor, I believe, any other analyst would ex-  
11 pect to see in an area where a reservoir is in -- is in  
12 pressure communication throughout and there is both fluid  
13 communication and thus pressure communication, what I found  
14 was that that was nowhere near the case. I had to start  
15 erasing some of the my contours from the western 2/3rds of  
16 this exhibit because they could not be contoured into nor  
17 be symmetrical with the vertical contours on the righthand  
18 side, so it was obvious that the -- there was a major  
19 change in pressure behavior at some point, a north- south  
20 line between Well A-20 on the west and Well E-10 on the  
21 east. I stopped at that point and went to the next map and  
22 --

23 Q Let us introduce Exhibit Forty-eight now  
24 and go to what you refer to as Exhibit -- the next map,  
25 which is Exhibit Forty-nine, which is the 11-19-87 pressure

1 period, pressure test period, Figure 3, page 24.

2 MR. DOUGLASS: And I will of-  
3 fer Exhibit Forty-eight. This will be Forty-Nine.

4 MR. LEMAY: It will be accept-  
5 ed without objection.

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

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

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

16 In a like manner, where there was a well  
17 that did not have pressure survey under date of November,  
18 19, 1987, I looked to either the preceding exhibit which  
19 was for date of June 30, 1987, or succeeding pressure date  
20 of February 23, 1988, in order to reach in my view a rea-  
21 sonable estimate of what the pressure was on November 19,  
22 1987.

23 Exhibit Forty-nine, therefore, contains  
24 15 major pressures that were reported on this exhibit by  
25 Mr. Weiss. It has one additional major pressure that I'll

1 discuss later, and it contains five wellbores and pressures  
2 on which I have estimated on Exhibit Forty-nine.

3           The configuration is essentially the  
4 same except that if one compared Exhibit Forty-Eight and  
5 Forty-nine, you would find that the maximum pressure isobar  
6 or contour, from Exhibit Forty-eight was 1200 psi in the  
7 Gavilan and expansion area of the exhibit, whereas on Exhi-  
8 bit Forty-nine the maximum isobar or pressure contour was  
9 100 -- 1000, excuse me, 1000 psi, and there was like reduc-  
10 tion in the remaining isobars, or contour lines, on Exhibit  
11 Forty-nine. That's with respect to the western 2/3rds of  
12 Exhibit Forty-nine.

13           With respect to the eastern 1/3rd, or  
14 the righthand 1/3rd of Exhibit Forty-nine, the pressure  
15 isobars were almost identical to those on the preceding ex-  
16 hibit, even though it's my understanding that during that  
17 intervening time, that the Gavilan and expansion area had  
18 produced at what I've heard described as normal allowables  
19 or higher rates of production, that seems to me to have had  
20 absolutely no pressure impact on the pressure maintenance  
21 area. Those contour lines stayed precisely where they  
22 were; the values are the same; yet there was about a 200  
23 pound reduction in pressure on the west side in terms of  
24 maximum pressures, or the largest isobar on the exhibit.  
25

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

6                   Q           Mr. Powell, I noticed that the pressure  
7 by the C-34 Well of 1395, which appears to be on the wrong  
8 side of your 1400 psi line, seems to be pressure slightly  
9 in excess of 1400 pounds rather than one slightly less than  
10 1400 pounds. Have you got that well mis-spotted there as  
11 far as pressure is concerned?

12                  A           No, not in my opinion. I need to ex-  
13 plain that and I'm glad you brought that up.

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

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

23                               That wellbore was not on the -- the ex-  
24 hibit that was originally prepared by Mr. Weiss as his Fig-  
25 ure 3 on page 24. It was brought to my attention after I



1 had completed my interpretation of the structural contour  
2 lines --

3 Q You said structure.

4 A -- excuse me, these pressure isobars,  
5 that there was a pressure available for Well C-34 that was  
6 contemporaneous in time with the November 19, 1987, pres-  
7 sures that are shown on Exhibit Forty-nine. I was instant-  
8 ly curious about that because it would have, obviously have  
9 some impact on -- on the contouring interpretations that I  
10 had done on Exhibit Thirty-nine without being aware that  
11 such a pressure existed.

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

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

22 MR. DOUGLASS: Offer Exhibit  
23 Forty-nine.

24 MR. LEMAY: Accepted without  
25 objection.

1           Q           And as Exhibit Fifty I'd like to have  
2 identified the February 23rd, 1988 pressure survey, Figure  
3 4, page 25 out of Mr. Weiss' Exhibit.

4                   Tell us what you've shown with Exhibit  
5 Fifty.

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

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

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

23                   I then contoured points of equal pres-  
24 sure value and I find that the -- that the general trend of  
25 pressure, the pattern of pressure, for these two very

1 separate and very distinct producing areas is the same.  
2 There had been intervening production and primary between  
3 the date of November, 1987, which was Exhibit Forty-nine  
4 and this February 23, 1988 date, which is Exhibit Fifty.  
5 The primary thing that I see on the left 2/3rds is that the  
6 area contained within the 1000 psi contour, or isobar, had  
7 decreased substantially in size and that there were --  
8 there was a general look-alike to the prior survey but at  
9 mostly diminished values.

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

16 It is inescapable that these two areas  
17 on Exhibits Forty-eight, Forty-Nine and Fifty are not com-  
18 mon sources of supply. They are not fluid communicated.  
19 They are not pressure communicated, and there is some bar-  
20 rier or impediment to flow and communication between the  
21 two areas.

22 I may explain that after I had not been  
23 able to draw my contours or isobars showing a gradual pres-  
24 sure differential across these three maps from -- beginning  
25 on high pressures on the east to lower pressures on the

1 west, that simply is not a procedure that's compatible with  
2 the pressure values that we see here. It was obvious that  
3 there was something that had to be placed in between those  
4 two areas where I had to break the continuity in my con-  
5 touring either going from left to right or from right to  
6 left. I simply could not join those two areas. I perhaps  
7 mechanically could have done it by stacking contours and  
8 drawing those pressure contours in there and cramming all  
9 of that substantial 500+ pound differential between these  
10 two areas into a horizontal distance less than one inch,  
11 and that would have stacked these or compressed the con-  
12 tours on top of each other, and when you find that, any an-  
13 alyst is going to look for an answer to why that has hap-  
14 pened; the same thing a geologist does when his contours on  
15 top of a producing formation are stacked, are very compres-  
16 sed, and a dramatic change in slope takes place.

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

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

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

15 Q Mr. Powell, do you think you need 1000  
16 pound pressure differential in order to establish a separa-  
17 tion between reservoirs of the sort that you're dealing  
18 with here?

19 A No, absolutely not.

20 MR. DOUGLASS: Pass the wit-  
21 ness.

22 MR. LEMAY: Let's take a  
23 break, fifteen minutes. We'll come back at 10 minutes to  
24 11.  
25

1 (Thereupon a recess was taken.)

2  
3 MR. LEMAY: We will continue  
4 with the questions for Mr. Max Powell.

5 Does Mr. Pearce have any  
6 questions?

7 MR. PEARCE: No, nothing to-  
8 day.

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

12 We'll come back then. Mr.  
13 Kellahin?

14 MR. KELLAHIN; Thank you, Mr.  
15 Chairman.

16  
17 CROSS EXAMINATION

18 BY MR. KELLAHIN:

19 Q Mr. Powell, let me draw on your exper-  
20 ience before the Railroad Commission, if I might, sir.

21 Do the rules of the Texas Railroad Com-  
22 mission provide for oil and gas operators to operate a  
23 pressure maintenance unit and project in only part of re-  
24 servoir?

25 A Yes, in either a cooperative pressure

1 maintenance and/or injection modern or under partial field-  
2 wide unit operations.

3 Q The rules of the Texas Railroad Commis-  
4 sion do then allow the opportunity to put in a secondary  
5 recovery project or a pressure maintenance project in only  
6 part of a reservoir?

7 A Yes. The matter of unitization is per-  
8 missive. The regulatory agency does not have legislative  
9 authority to require compulsory unitization. It only has  
10 the authority to approve or disapprove unitized projects  
11 that are tendered to it for approval.

12 Q When a pressure maintenance project is  
13 tendered to the Railroad Commission that incorporates a  
14 voluntary agreement of all those working interest parties  
15 and the Texas Railroad Commission reviews that and deter-  
16 mines whether or not it is technically competent and feas-  
17 ible to approve the project?

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

25 In addition to that the technical merit

1 of the proposed project, whether it be for pressure main-  
2 tenance or secondary recovery, dealing with an essentially  
3 depleted primary supply, is looked into.

4 Q And I take it that the Railroad Commis-  
5 sion, in fact, has exercised those authorities and approved  
6 such projects?

7 A Yes. many times.

8 Q Does the rules of the Texas Railroad  
9 Commission provide an opportunity for the pressure mainte-  
10 nance operators and interest owners to receive a credit  
11 for the gas withdrawn from the unit and then reinjected  
12 back into the project?

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

17 Q That's exactly right.

18 A That is a customary practice.

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

22 A It has to do with either diminishing or  
23 minimizing reservoir withdrawals. If -- that is more asso-  
24 ciated with pressure maintenance type operations than with  
25 pure secondary, and I distinguish between those two in that



1 secondary ordinarily deals with essentially depleted oil  
2 reservoirs whereas pressure maintenance is involving an on-  
3 going primary project.

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

9 A Yes, you will find that, Mr. Kellahin.  
10 You will not find it with great frequency in the circum-  
11 stances that you have just described. It is more ordina-  
12 rily found that where gas injection primarily is the in-  
13 jection medium, that you will more often than not have  
14 field-wide units formed. Gas is more transitory than is  
15 water, obviously, and it tends to put at least the gas in  
16 more mobile fashion and it does not honor leaselines very  
17 well.

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

22 A Essentially that. It can be either re-  
23 placing all of the reservoir voidage, in which case you  
24 have a true pressure maintenance, no reduction in pressure  
25 during the producing phase. It can be partial.

1           Q           As hearing examiner before the Railroad  
2 Commission, Mr. Powell, did you have occasion, sir, when  
3 you had before you for a decision geologists you knew per-  
4 sonally and professionally, both of whom you had high re-  
5 gard in respect for their ability, in which they would take  
6 the same structural data points and contour for you on a  
7 structure map significantly different contours, and each of  
8 those experts giving you a different point of view on how  
9 that structure is displaced.

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

12           Q           Yes, sir.

13           A           Yes, I have.

14           Q           And as a regulator have you seen geolo-  
15 gists that also take the same information and give you an  
16 isopach that is significantly different when each of those  
17 gentlemen contour that data?

18           A           Yes, but more often than not, when one  
19 is dealing with isopachic (sic) interpretations, the reason  
20 for variance in configuration of the thickness lines, I  
21 found more often than not was associated with the basic  
22 data on which they were relying. Some, for example, would  
23 isopach gross thickness; others would isopach net thickness  
24 and the closer one comes to isopaching the true hydrocar-  
25 bon pore volume, thee the more opportunity there is for

1 disagreement and dispute about the parameters, such as  
2 porosity and the oil and water saturations.

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

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

11 Q Let me identify for you on the bas map,  
12 Proponents Exhibit Number Five, Mr. Powell, let me locate  
13 for you what is the unit well, the K-13. It's in Section  
14 13 here in the main part of the pressure maintenance area.  
15 Do you show that on each of your three exhibits?

16 A I do.

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

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

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

25 On Exhibit Fifty, which is the pressure

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

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

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

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

13 A You're asking me to assume that?

14 Q Yes, sir.

15 A All right, I can assume that.

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

22 A I don't know whether it would or not,  
23 Mr. Kellahin. I am not aware of any such pressure as the  
24 well that you described. If I had such a pressure, I would  
25 analyze it with respect to all of the other pressures and

1 data that I had and reached a conclusion. I can't do that  
2 in the absence of a pressure.

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

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

16 MR. KELLAHIN: Nothing further.

17 MR. LEMAY: Mr. Carr, any  
18 questions?

19 MR. CARR: No questions.

20 MR. LEMAY: Additional ques-  
21 tions of the witness?

22 Mr. Chavez.

23  
24 QUESTIONS BY MR. CHAVEZ:

25 Q Mr. Powell, in the testimony that was

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

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

5 Q Well, the record that you recall that  
6 was presented to you as an examiner in the hearing of the  
7 Spraberry cases, did you take a look at bottom hole pres-  
8 sures?

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

13 Q Just in general, then, would you consi-  
14 der a pressure difference of 500 psi between wells in a  
15 pool, shut-in bottom hole pressures, that is, to be indica-  
16 tive that the wells may not be in the same pool?

17 A Given only the one parameter, Mr.  
18 Chavez, I do not believe that a reasonable analyst, and I  
19 hope I would qualify as such, would come down with a con-  
20 clusion on that limited volume of data. I not only looked  
21 to pressure differential, I look to distribution of pres-  
22 sure differential and where it is and what the patterns  
23 look like before making a decision as to whether I'm deal-  
24 ing with one common source of supply or multiple sources.

25 Q Would you also take a look at production

1 rates in the areas where the pressures are different to  
2 determine whether or not the differences may be caused by a  
3 difference in the production rates?

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

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

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

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

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

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

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

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

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

19          A           Well, I see overall minimum pressures on  
20 this graphic representation on the upper righthand corner  
21 of page 187, the minimum pressure is slightly more than  
22 1400 pounds and the bulk of the upper level pressures are  
23 just below 2000. There is one that appears to be out of  
24 context with the others that's just less than 2200. So  
25 there's generally about a 600 pound spread on that graphic



1 representation.

2 Q Thank you. That's all I have.

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

9 Q Yes, I understand that. Thank you.

10 MR. LEMAY: Thank you, Mr.  
11 Chavez.

12 Additional questions of the  
13 witness?

14

15 REDIRECT EXAMINATION

16 BY MR. DOUGLASS:

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

20 A Yes, I do.

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

25 A Oh, yes. The trends of the pressures is

1 a major consideration and the exhibit that Mr. Chavez re-  
2 ferred me to shows that there was almost equal decline in  
3 bottom hole pressure over the period of time considered in  
4 the graph from -- between wells shut-in as was experienced  
5 by wells that were producing, and that is dramatic evidence  
6 of excellent communication.

7 Q All right, sir. Pass the witness.

8 MR. BROSTUEN: I have one.

9 MR. LEMAY: Mr. Brostuen.

10  
11 QUESTIONS BY MR. BROSTUEN:

12 Q Mr. Powell, in your discussion of your  
13 Exhibit Number Forty-seven, you talked about the perform-  
14 ance of several gas injection projects in the Spraberry  
15 Trend Area Field and all of the -- there were three pro-  
16 jects, all were indicated to be failures.

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

21 A Yes, you did hear that.

22 Q And have you evaluated the gas injection  
23 and performance in the Canada Ojitos Unit and formulated an  
24 opinion as to the effectiveness of the gas injection and  
25 whether or not it may have been detrimental to the ultimate

1 production of oil from that reservoir?

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

5 Q Sure.

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

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

22 That is not to be compared, however, in  
23 my view with injecting gas into an existing oil column  
24 where one does not have the structural benefit for the gas  
25 accumulation to be on top of the oil. I think that's vast-

1 ly different on the east side of this area than the west  
2 side where there is not that dramatic structural relief.

3 With respect to whether it's beneficial,  
4 if that's a part of your question, I have not made an as-  
5 sessment of that. I have generally expected to see some-  
6 what more definitive analyses done of the success or fail-  
7 ure of that effort and that would include knowing what the  
8 original oil in place would have been for that unit area;  
9 what the oil could have been expected to be realized under  
10 primary operations, and by that I mean absent any injec-  
11 tion of any kind, and then quantifying of what has actually  
12 been achieved.

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

17 The only reference that I have seen, and  
18 I'm not critical of that, it's just an observation on my  
19 part, is that there is one well in the unit area that has  
20 produced 2-million barrels of oil and that then is taken to  
21 support the concept that the gas injection project has been  
22 eminently successful. I don't buy that, and perhaps that's  
23 just my way of analyzing things, but there's a great deal  
24 more to look to before one could say, yes, that it has been  
25 successful partially, or it has had little to no impact,

1 and if the only supporting data is one well having made  
2 2-million barrels of oil, that in my view is nowhere near  
3 sufficient on which to make an assessment that this project  
4 has in fact been successful.

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

9 Q Well, would you, whether or not you sub-  
10 scribe to the re-imbibition theory or not, I don't recall  
11 whether you've said one way or the other on that; however,  
12 would it appear to you that by maintaining reservoir pres-  
13 sure by gas injection would increase the -- the re-imbibi-  
14 tion of oil into the matrix and increase -- result in the  
15 counter flow of gas out of the matrix into the fractures  
16 and in a sense improve production more?

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

21 I am also a proponent of the reservoir  
22 engineering concept that in a fractured environment such as  
23 I understand exists at Gavilan and the extension area, or  
24 proposed expansion area, and perhaps don't refer to that  
25 properly, if there is heavy fractures evident there, I be-

1 lieve, and support the concept that the maximum ultimate  
2 recovery of oil will be realized by maximizing the pres-  
3 sure differential between the fracture, which is the trans-  
4 port vehicle or the pipeline from the matrix to the pro-  
5 ducing well. I firmly support that concept and that is not  
6 a new position for me; it goes back many years, that ulti-  
7 mate recovery is enhanced by maximizing that pressure dif-  
8 ferential; stated another way, keeping the fracture pres-  
9 sure as low as possible by producing producing wells to  
10 capacity.

11 That's not to say that I'm not also an  
12 advocate of secondary recovery, Mr. Commissioner, I am. I  
13 have engaged in it and participated in it to a major ex-  
14 tent. I do not subscribe, however, and I am not a proponent  
15 of putting to risk known primary reserves in the hope or  
16 the expectation of an injection project that might or might  
17 not increase the ultimate secondary recovery. I don't be-  
18 lieve and I don't subscribe to risking a known for an un-  
19 known percentage additional gain. I much more favor the  
20 primary depletion process that will yield the maximum ulti-  
21 mate recovery and then put that remaining reserve at risk  
22 under a project that is best assigned to handle the circum-  
23 stances at that time. You're no longer risking the primary  
24 recovery; you have that and it's been achieved.

25 So the benefit of a secondary project at

1 that time can -- can only be on the plus side if it's  
2 successful and you don't lose anything if it's unsuccess-  
3 ful except the money to do it.

4 Q Thank you very much.

5  
6 QUESTIONS BY MR. LEMAY:

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

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

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

20 Q I like your democratic process.

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

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

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

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

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

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

17          A           I have not quantified that. I've looked  
18 through a large number of -- in fact every large secondary  
19 recovery project and I think the most successful one, and  
20 that is the project in which Mr. Lincoln Elkins was invol-  
21 ved, and that is SOHIO Petroleum's Driver Unit. In terms  
22 of numbers of barrels it has recovered far more barrels  
23 than any other secondary recovery project in Spraberry, but  
24 I believe that, my memory is that through the end of 1987  
25 those secondary recovery operations by SOHIO, as successful



1 as they were, and only in comparison with other projects  
2 could you qualify it as being very successful. The addi-  
3 tional recovery due to secondary is substantially less than  
4 3 percent of the original --

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

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

24 I've found, if I don't run on too long  
25 in response to your question, I don't intend to belabor it,

1 in my analysis I only found one project that recovered  
2 through the end of 1987 more oil than the operator expected  
3 to recover when the project was initiated, and I was cur-  
4 ious to know how that happened, because everybody else had  
5 gotten many multiples less than they expected, and I found  
6 that that operator didn't expect to get anything anyway, so  
7 everything was a surprise, and he's estimated his secondary  
8 ultimate recovery at 0.4 percent of primary, and with that  
9 kind of -- sort of unrealistic low thing, it wasn't too  
10 difficult to achieve more. But he's the only one that out-  
11 did his expectations but he did that by not expecting any-  
12 thing.

13 Q Are you familiar with the Austin Chalk?

14 A Yes.

15 Q Have there been any recovery efforts to  
16 date, to your knowledge, in that either waterflood or pres-  
17 sure maintenance in that trend area?

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

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

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

14 MR. LEMAY: Thank you, Mr.  
15 Powell.

16 Are there additional questions  
17 of the witness?

18 If not, he may be excused.

19 MR. DOUGLASS: That's our  
20 case.

21 MR. LEMAY: Thank you, Mr.  
22 Douglass.

23 Mr. Pearce, do you have direct  
24 witness?

25 MR. PEARCE: I do not, Mr.

1 Chairman.

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

4 MR. LOPEZ: Nothing.

5 MR. LEMAY: Is Amoco still  
6 (not clearly understood), yeah. You don't have any wit-  
7 nesses for the Proponents?

8 MR. LUND: Not for the direct  
9 case.

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

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

18 We believe that in cross exam-  
19 ination we have used 2 hours and 45 minutes, approximately,  
20 of time in examining not only the Commission witnesses but  
21 the Proponents witnesses.

22 That's how we see the time  
23 thus far.

24 MR. LEMAY; Thank you, Mr.  
25 Kellahin.

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

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

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

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

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

18

19 (Thereupon the noon recess was taken.)

20

21 MR. LEMAY: The hearing will  
22 resume.

23 Mr. Kellahin.

24 MR. KELLAHIN: Thank you, Mr.  
25 Chairman.

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

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

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

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

14  
15 WILLIAM JOHN LEE,  
16 being called as witness and being duly sworn upon his oath,  
17 testified as follows, to-wit:

18  
19 DIRECT EXAMINATION

20 BY MR. KELLAHIN:

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

23 A Yes, I was.

24 Q Dr. Lee, in the past have you been re-  
25 cognized by this Commission as an expert witness in the

1 field of petroleum reservoir engineering?

2 A Yes, I have.

3 Q And did you testify on behalf of Benson-  
4 Montin-Greer, Sun Production and Exploration Company, in  
5 the Gavilan Mancos hearings held in March and April of  
6 1987?

7 A Yes, I did.

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

11 A Yes.

12 Q Did you study of the Gavilan Mancos -  
13 West Puerto Mancos reservoir commence prior to the March,  
14 1987 hearing?

15 A Only slightly before, yes.

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

18 A Yes, I have.

19 Q Dr. Lee, have you been present through-  
20 out this week through all the testimony of the witnesses  
21 thus far in the case?

22 A Yes, I have.

23 MR. KELLAHIN: Mr. Chairman, I  
24 tender at this time Dr. John Lee as an expert petroleum en-  
25 gineer.

1 MR. LEMAY: Dr. Lee's quali-  
2 fications are acceptable.

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

7 A Yes, sir, I did.

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

12 A Yes.

13 Q -- this display here?

14 A Yes.

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

17 A That's correct.

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

22 A Yes, that's correct.

23 Q And is it your understanding, sir, that  
24 the area outlined in by the pink marker is the area con-  
25 tained within the West Puerto Chiquito Mancos Pool?



1           A           Yes.

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

5           A           Yes. My objective was to apply fairly  
6 simple material balance calculations to the pools and to  
7 try to avoid any complex mathematical computer model, but  
8 to be valid material balance calculations require that the  
9 area studied have reasonably uniform oil and gas satura-  
10 tions throughout the area and reasonably uniform pressures  
11 throughout the area, and, of course, that's not true for  
12 these pools as a whole, and therefore, I had to break the  
13 pools into five separate tanks, as I'll call them, in order  
14 to have areas in which I could satisfy the needs of apply-  
15 ing material balance calculations.

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

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

23           Q           Are these standard, well accepted, engi-  
24 neering calculations to explain observed reservoir facts?

25           A           Yes. Material balance calculations are

1 well accepted when the conditions for their applicability  
2 are satisfied.

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

7 A Well, within each tank what I do is as-  
8 sume some amount of oil in place in that tank originally,  
9 and then I look at the production of oil and gas from that  
10 tank and with a given amount of production a certain pres-  
11 sure drop will result. The more oil and gas we take out  
12 the more the pressure will drop.

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

17 Well, I continue this process and after  
18 I've generated a number of pressures resulting from these  
19 production amounts of oil and gas, then I look at my calcu-  
20 lated pressures and if I go back all the way to the start  
21 of the pool, I have observed pressures from these tanks  
22 that I can compare calculated pressures to. I do the very  
23 best I can to try to match these observed pressures. Per-  
24 haps the original assumption of oil in place within a tank  
25 was incorrect. I'll adjust that.

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

7                   Q           In linking these tanks you determined  
8 the oil resistance characterized by the affected permeabil-  
9 ity, the thickness products, needed to match the actual  
10 observed past performance?

11                  A           That's a good summary.

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

15                  A           Yes, it is.

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

19                  A           Yes, sir, that's correct.

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

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

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

6           Q           Would you please explain the exhibit to  
7 the Commission?

8           A           Yes. The major purpose of this exhibit  
9 is to simply orient you and show you what the final result  
10 of this trial and error process to identify the most prob-  
11 able oil in place that I could find and most probable flow  
12 resistance between tanks turns out to be that is that de-  
13 scription which leads to the best match that I can obtain  
14 of observed calculated pressures in this reservoir.

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

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

22           A           Yes, that's correct.

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

1           A           Well, because that tank is characterized  
2 by the fact that all the gas injection in the unit occurs  
3 there. The pressure within that tank is reasonably uni-  
4 form. There are reasonably uniform fluid saturations in  
5 that tank because of the injection.

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

10          A           Yes, it is.

11          Q           And as we move farther west, did you use  
12 as a tank the two rows of sections that represent the ex-  
13 pansion area?

14          A           Yes.

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

18          A           Yes, I have.

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

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

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

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

5 Q How well do the pressures observed his-  
6 torically in the area of these tanks match the pressures  
7 that you've calculated by this method?

8 A I think they agree reasonably well.

9 Q Have you prepared an exhibit that il-  
10 lustrates this comparison between calculated and observed  
11 pressures.

12 A Yes, I have.

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

15 A Yes. it is.

16 Q Would you please explain this exhibit to  
17 the Commission?

18 A What this exhibit is, is a verification  
19 or at least a comparison of calculated and measured pres-  
20 sures from this material balance work which I've been de-  
21 scribing earlier

22 What we have here, what is on the verti-  
23 cal axis, is the pressure in each of the five tanks con-  
24 verted to a datum pressure at +370 feet above sea level.

25 On the horizontal axis we have the date

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

5 What we have on the graph, as I indicat-  
6 ed earlier, is different lines, 5 different lines, which  
7 represent the calculated pressures in each of the 5 differ-  
8 ent tanks, and the symbols on this diagram represent obser-  
9 ved pressures. Now the lines and the symbols are color  
10 coded to aid in the identification of which area's pressure  
11 calculations are shown in a certain color and the measured  
12 or observed pressures which correspond to that particular  
13 tank.

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

19 And the symbol for the observed pres-  
20 sures in that area, we have a -- also a green cross.

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

25 The lowest pressures that are shown here

1 generally are the black line. That's the calculated pres-  
2 sures in the western end of Gavilan.

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

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

8 A I think it's pretty good. It's certain-  
9 ly not perfect but considering the heterogeneity in this  
10 reservoir, considering some of the problems in pressure  
11 maintenance itself, I would say it's a pretty good agree-  
12 ment. I would say particularly so since about 1985, where  
13 I think we follow in some detail the general trends in the  
14 observed pressures in the field and this is important be-  
15 cause it's during this time period in which the withdrawals  
16 have begun to accelerate and the pressures in the various  
17 areas of the field have really begun to spread apart and  
18 identify themselves.

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

21 A The lines on the display are volume  
22 average pressures. That's pressure which I used to char-  
23 acterize that entire tank, which, of course, contains many  
24 sections, and therefore we shouldn't be surprised to have  
25 some variation of observed pressures within that tank, but



1 our hope is to characterize that tank pretty adequately  
2 with this line.

3 Q Did you calculate the pressure differ-  
4 ences between the project area, which means the Canada  
5 Ojitos Unit project exclusive of the expansion area, taking  
6 that on one side, and the pressure differential in the ex-  
7 pansion area, do you -- do you calculate pressure differ-  
8 entials as large as those presented by Mallon in the March,  
9 1988, pressure expansion case?

10 A Yeah, I think the magnitude of the pres-  
11 sure differences are comparable, some 3-to-400 psi pressure  
12 difference between the central part of the Canada Ojitos  
13 Unit as compared with observed between the unit and the ex-  
14 pansion area as compared with, say, 400 or more psi obser-  
15 ved pressure difference between the pressure maintenance  
16 area and the proposed expansion area.

17 A Mr. Hueni says that a barrier between  
18 the expansion area and the project area is required to ex-  
19 plain those pressure differentials, is that correct?

20 Q No, I would propose that there is an al-  
21 ternate explanation simply by finding the flow resistances  
22 that I've found, which really constitutes a variation in  
23 permeabilities throughout the area; that is, some degree of  
24 heterogeneity. I certainly haven't captured all the detail  
25 with this 5-tank model, but at least with changes in perme-

1 ability, and also I would say importantly, because of the  
2 very large amount of gas injection into this pool. In fact,  
3 an amount of gas injection so large that throughout much of  
4 history the pressure throughout the pool has actually been  
5 above the discovery pressure, which means more injection  
6 than total oil and gas production from the pool.

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

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

12 A No, it is not.

13 Q Mr. Hueni assumed a barrier would be re-  
14 quired to account for the observed pressure differences,  
15 did he not?

16 A Yes, he did.

17 Q Is he presenting the kind of calcula-  
18 tions you have?

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

24 Q When you look at the Gavilan Mancos Pool  
25 itself, and that's identified in the green area, within

1 that area itself have you observed and calculated pressure  
2 differences within that area from the east side of Gavilan  
3 to the west side of 2-to-300 pounds differential?

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

8 Q During late 1987 within Gavilan itself  
9 what have you observed to be the range of pressure differ-  
10 entials during that period of time?

11 A During late 1987?

12 A Yes, sir.

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

17 Q What does that calculate to be a gradi-  
18 ent in terms of pressure per mile within Gavilan?

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

22 Q Does it make sense to you as a reservoir  
23 engineer to say that there is in fact a barrier located be-  
24 tween the expansion area and the project area and not a  
25 barrier within Gavilan itself?

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

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

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

15           A           Exhibit Number Two summarizes calcula-  
16 tions and conclusions based on those calculations concern-  
17 ing migration across this alleged barrier, with this cal-  
18 culation being based on pressures observed between  
19 6-30-1987 and 2-23-88.

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

23           A           Mr. Kellahin, if I might, I'd really  
24 like to refer first to the second page, which is a summary,  
25 and then come back to the first page and provide the de-

1 tial on which the conclusion on the summary page is based.

2 Mr. Max Powell this morning pointed out  
3 to the Commission that the pressure in the Canada Ojitos  
4 pressure maintenance area had remained constant at about  
5 1500 pounds from June 30th, 1987, through February, 1988, I  
6 believe, actually the dates that -- for which he provided  
7 the final pressure estimates were February 23rd, or so, but  
8 anyhow, generally, between the first of July and the first  
9 of March, he noted, and provided on exhibits information  
10 indicating that the pressure had remained constant.

11 Looking at what pressure might charac-  
12 terize that area as a whole, I would judge from his exhibit  
13 that the pressure on the average remained constant at about  
14 1500 pounds per square inch with -- with some variation ac-  
15 cordng to the pressure gradients that he drew on his exhi-  
16 bit this morning.

17 Q You're specifically referring to his  
18 Exhibit Forty-eight, Forty-nine and Fifty from this morn-  
19 ing?

20 A Yes, sir, I am. Now, the implication of  
21 that important observation, Mr. Powell says, that whenever  
22 the pressure remains constant over some period of time,  
23 then we can make some important and revealing calculations  
24 about migration into or out of an area. We can do this  
25 very simply by noting that net migration has to be the dif-

1       ference between the injection of gas in that time period  
2       and the amount of production of oil and free gas during  
3       that same time period with each of these quantities expres-  
4       sed in reservoir barrels, because the pressure doesn't  
5       change, there's no expansion or shrinkage of the fluids re-  
6       maining in that area, it's simply what goes in has -- less  
7       what comes out, the difference in those has to be what  
8       moved out through the process of migration.

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

13              Based on Mr. Powell's observation that  
14       pressure remained constant at 1500 pounds, I calculated  
15       that migration from the pressure maintenance area across  
16       this so-called barrier during this period from June 30th,  
17       '87, to February 29th, '88, was 624,000 reservoir barrels.  
18       The conclusion that I reach is that this barrier is not a  
19       seal. It's certainly not a barrier.

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

23              I've identified on the front page some  
24       of the detailed information on which this calculation is  
25       based. I've noted from our production records on 6-30-87

1 and 2-29-88, which is really the date on which our pro-  
2 duction records are available, the cumulative oil produc-  
3 tion that we have on our records from this pressure main-  
4 tenance area. I've also noted the cumulative gas produc-  
5 tion and the cumulative gas injection into the area, and of  
6 course the difference in these cumulative totals that we  
7 have in our records would be the incremental amounts of  
8 production and injection that occurred during this time  
9 period.

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

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

1 370-foot datum, multiply by the gradient, the pounds per  
2 square inch per foot change in pressure as I go from datum  
3 into the area, and that gives me a pressure of approximate-  
4 ly 1180 pounds per square inch.

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

8 Now, to make the calculation I'm going  
9 to need some factors with which I can convert production  
10 volumes and injection volumes expressed at surface condi-  
11 tions into volumes at reservoir conditions, so-called for-  
12 mation volume factors, From tabulated fluid properties I  
13 could look these up. Now I'm ready to make my calculation.

14 Total production during this time period  
15 is equal to the surface oil rate times the oil volume fac-  
16 tor, using the symbols  $Q_O$  and  $B_O$  here, and the gas rate,  
17 this has to be free gas rate, not gas that was (unclear) in  
18 the oil but free gas, so I take the total gas produced,  
19 subtract from it the gas that was dissolved in the oil, and  
20 then convert that to reservoir conditions with a volume  
21 factor.

22 The result is I find that 743,000 reser-  
23 voir barrels have been produced. That's oil plus free gas.

24 Next I take my injection and convert  
25 that to reservoir conditions and find that 1367-thousand



1 reservoir barrels of gas have been injected during this  
2 time period.

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

11 So I conclude, based on these calcula-  
12 tions that there's been net migration of 624,000 reservoir  
13 barrels.

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

18 A That's correct.

19 Q One of Mr. Hueni's exhibits, Proponents  
20 Exhibit Twenty, Mr. Hueni discussed with the Commission the  
21 fact that he found, based upon his analysis of the data,  
22 that the unit had a certain pressure at the time Gavilan  
23 was discovered and he displayed that by showing a dashed  
24 line on Exhibit Twenty and related that back to pressures  
25 taken in Gavilan. In doing so did Mr. Hueni take into con-

1 lideration the over-injection of gas that was taking place  
2 in the unit?

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

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

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

18 A Yes, sir.

19 Q When we get to that point on your dis-  
20 play what happens to this line that Mr. Hueni has projected  
21 as a slowly declining line?

22 A Well, it's at exactly that point that  
23 the over-injection began. More gas began to be injected  
24 than there was free gas and oil produced from the reservoir  
25 and therefore the pressure in the overall pool had to in-

1       crease in response to this more fluid coming in than going  
2       out.

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

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

12              Q              When you get to the point where Mr.  
13      Douglass has put on this display 350 pounds pressure dif-  
14      ferential between Gavilan and the unit, what do your calcu-  
15      lations show that pressure differential to approximate?

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

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

24              A              There's no barrier between the areas.

25              Q              In making your review of the observed

1 facts and doing the engineering calculations was it neces-  
2 sary for you to hypothesize a dual porosity reservoir to  
3 explain the observed performance of the field?

4 A No, it was not.

5 Q Why not?

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

11 In addition we are not at all convinced  
12 by the evidence saying that there is a dual porosity system  
13 in this reservoir. So we see no need to make that hypothe-  
14 sis.

15 Q Before we get to a discussion of the  
16 dual porosity issue, Dr. Lee, would you summarize for us  
17 then what your conclusions are based upon the material bal-  
18 ance calculations insofar as determining a flow barrier be-  
19 tween the expansion area and the project area?

20 A Well, briefly stated, I conclude that  
21 there is no flow barrier at the edge of the current pres-  
22 sure maintenance area in the Canada Ojitos Unit. The  
23 reason why is because observed pressure drops in the field  
24 in my judgement can be explained by permeability varia-  
25 tions rather than an absolute permeability barrier.

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

3 A Yes, sir, that's correct?

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

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

8 Q And what were those plans that you uti-  
9 lized future performance? Did you use one plan or did you  
10 have several different, alternative, operating plans for  
11 the field?

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

21 Now, for the pressure maintenance pro-  
22 ject there's still a question to be answered and that is  
23 what should be done with the oil, and particularly gas,  
24 withdrawals in the interim period between the time the pro-  
25 ject -- between now, or let's say July 1st, and the time

1 such a project could begin?

2 To answer this question I looked at  
3 three more possibilities, and that is, in the interim per-  
4 iod, continuing to produce the field under the current  
5 allowable of 800 barrels per day for 640 acres with a pen-  
6 alty gas/oil ratio of 600 cubic feet per barrel or a gas  
7 limit of 480 MCF per day of gas.

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

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

19 The third alternative that I looked at  
20 was to see what would happen if we increased the allowables  
21 to those used in the high test rate period, the allowables  
22 being 1280 barrels of oil per day with a penalty gas/oil  
23 ratio of 2000-to-1 or 2560 MCF per day of gas for a well on  
24 640-acre spacing.

25 Q In one of the plans we're talking about

1 pressure maintenance in the Gavilan Mancos Pool itself.

2 A That's correct.

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

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

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

22 A That's correct.

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

1           A           That's correct.

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

4           A           Yes, sir.

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

8           A           That's correct.

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

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

18          Q           Let me direct your attention, Dr. Lee,  
19 to page 5 of Exhibit One, now, and have you show us the  
20 calculations and the support by which you reached that con-  
21 clusions.

22          A           All right. First, I want to make a com-  
23 ment about page 5. In an earlier copy of the exhibits that  
24 we handed out to particularly the counsel for the Propo-  
25 nents the numbers were significantly different, and the



1 reason that they were different was because we completely  
2 messed up our calculations. They were just plain wrong.

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

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

12 A Yes, that's correct.

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

15 A What this exhibit shows, it really ad-  
16 dresses the two different kinds of issues that I raised  
17 earlier.

18 First, what is the effect of pressure  
19 maintenance, and second, for a pressure maintenance project  
20 what will be the effect of different allowable schemes  
21 prior to implementation of the pressure maintenance pro-  
22 ject?

23 Now, first question, what's the effect  
24 of pressure maintenance?  
25

1 To answer that question we simply pro-  
2 jected the model forward to an economic limit of 400 bar-  
3 rels of oil per day total production from both pools and  
4 when it reached that limit we said we had our ultimate re-  
5 covery, and with continued current allowables we projected  
6 an ultimate recovery of 5439 thousand stock tank barrels.

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

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

21 I think the numbers are comparable and  
22 sort of serve as a check on each other, even though the  
23 type of reservoir model assumed was significantly differ-  
24 ent.

25 Q Within Gavilan under pressure mainten-

1       ance you have found that that improves recovery?

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

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

12              A           Well, basically, and this information  
13      summarizes the bottom half of this exhibit, basically, the  
14      lower the rate, particularly to the gas withdrawal rate,  
15      between now and the time of the implementation of a pres-  
16      sure maintenance project, the greater the ultimate recovery  
17      for that project; about 11-million barrels according to  
18      this calculation would be possible if we cut the gas back  
19      to the current solution gas/oil ratio; about 10-million  
20      barrels ultimate recovery if we maintain our current allow-  
21      ables; and about 7-1/2 million barrels recovery if we in-  
22      crease the allowables to the values that we had during the  
23      high test rate period in the field.

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

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

6           Q           Are additional recoveries due to pres-  
7 sure maintenance injection possibly greater than you calcu-  
8 lated?

9           A           Could be; could be less.

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

13          A           Well, my conclusion is simply that ulti-  
14 mate recovery in Gavilan can be increased by minimizing oil  
15 and gas withdrawals now, conserving reservoir for addition-  
16 al recovery with pressure maintenance later.

17          Q           What are your recommendations, Dr. Lee?

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

23                       The expansion area and the current pres-  
24 sure maintenance project area are in clear communication.

25                       The second recommendation is to maintain

1 the lowest oil rates, the minimum gas production possible.

2 Q These are shown on page 7 of your exhi-  
3 bit?

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

9 And then the third recommendation is  
10 sort of a truism, but I still feel that I need to say it,  
11 and that is that Gavilan operators really should be en-  
12 couraged to study and following that study, if they ident-  
13 ify economic viability, putting in the pressure mainten-  
14 ance project to improve recovery from the reservoir.

15 Q Dr. Lee, I'd like to go to a different  
16 subject at this time. I'd like to address the issue of mi-  
17 gration between Gavilan and the West Puerto Chiquito Mancos  
18 Pool.

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

23 A Yes, I did.

24 Q And have you made a study of that alle-  
25 gation?

1 A Yes, I have.

2 Q And what do you find?

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

5 Q Describe for us how you reached that  
6 conclusion.

7 A Well, basically, using the same simpli-  
8 fied material balance tank type models that I've used for  
9 the earlier parts of this study.

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

13 A Yes, I have.

14 Q Have you prepared an exhibit that demon-  
15 strates the results of this part of your study?

16 A Yes, I have. It's found starting at page  
17 9, but really the part that I want to get to is on page 10  
18 of the exhibit booklet, and I apologize for skipping pages  
19 but this was prepared as rebuttal testimony but I think  
20 since we've -- since I'm combining my rebuttal and direct  
21 testimony, I'm going to jump to this rebuttal section of  
22 the booklet now.

23 On page 10 I think we can see a graphic-  
24 al summary of the calculations that I've made.

25 Q Let me have you first of all explain the

1 exhibit to us and then let's talk about the conclusions.

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

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

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

16 Q What does it show you between the Gavi-  
17 lan and the West Puerto Chiquito Mancos Pools from the  
18 period of 1963 to 1972?

19 A Well, during the period from 1963 to  
20 1972, you'll notice that we have positive cumulative migra-  
21 tion. This means that migration is coming from Gavilan  
22 into the proposed expansion area, and then at that point  
23 the direction of migration changes. Now remember what we  
24 have plotted here is cumulative migration.

25 So the rate was not necessarily increas-

1 ing but the amount of migration was accumulating, reached a  
2 maximum about 1972.

3 At that point the direction of migration  
4 turned around. We had at that point migration going away  
5 from the expansion area and back toward Gavilan. It  
6 crossed zero again in the late seventies, say, and particu-  
7 larly in the recent time period, according to these calcu-  
8 lations, there has been an increasing amount of migration  
9 from the proposed expansion area to Gavilan. Mr. Greer  
10 feels that he has a plan in effect now which should do a  
11 pretty good job of stopping oil migration but I think the  
12 calculations, although they can't be taken literally in the  
13 sense of quantifying with any precision the amount of mi-  
14 gration, I think, at least do show the direction of migra-  
15 tion, and leave us, in my judgment, with net migration from  
16 the expansion area to Gavilan.

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

23 A That's correct.

24 Q And then if we reverse the process and  
25 put the page above the zero line on the display, there's a



1 certain portion on the horizontal date scale in which the  
2 line is obviously evident.

3 A That's correct.

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

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

8 Q Would migration from West Puerto Chi-  
9 quito Mancos to Gavilan be even greater if oil and gas  
10 rates were increased in Gavilan?

11 A Well, at least protection of the bound-  
12 ary would become more difficult.

13 Q What is the basic cause of the past mi-  
14 gration, Dr. Lee?

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

25 As there was more and more over-injec

1     tion the pressure difference built up. Gavilan was fin-  
2     ally developed, oh, first well in about 1982, but really  
3     significant production began in 1984 and 1985 and that's  
4     the period in which substantial pressure difference devel-  
5     oped. Now Mr. Greer is implementing his boundary protec-  
6     tion plan, minimizing the pressure gradients. Looking at  
7     displays of pressures on the other exhibits, I'd say, you  
8     know, you can look at some wells and say the pressure  
9     gradient is one way and others say the pressure gradient is  
10    the other way. I'll say that at this point we've probably  
11    substantially halted cumulative of oil migration.

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

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

1 with increasing pressure gradients.

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

4 A Page 12 simply puts together in one  
5 graph the migration on a cumulative basis from the current  
6 pressure maintenance area into the proposed expansion area  
7 the cumulative migration into the proposed pressure main-  
8 tenance expansion area from Gavilan.

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

12 A Yes, I have.

13 Q Would you like to present that now?

14 A Yes. I'd really like to start with a re-  
15 sponse to Mr. Elkins' comments yesterday. I think this is  
16 an appropriate place to make those comments.

17 Q Let's refresh everyone's recollection.  
18 Yesterday Mr. Elkins described his calculations and assump-  
19 tions and said that there were portions of your prior work  
20 in March of '87 with which he agreed and there were other  
21 portions of your calculations with which he disagreed.

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

1 nificant to us?

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

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

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

15 So we agree on the fact that we can get  
16 permeability thickness product from a properly run inter-  
17 ference test, and the analysis that he cited he said  
18 directionally agreed with the results that Mr. Greer and I  
19 got.

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

1 Well, I'd like to point out that I  
2 really agree totally with that recommendation. When I ana-  
3 lyze an interference test I always calculate porosity  
4 thickness, as well as permeability thickness, and in fact,  
5 the basis for the porosity thickness product that we have  
6 used throughout this study is based on analysis of these  
7 interference tests, but it's based on an analysis of all  
8 the interference tests that we can look at and our percep-  
9 tion is that the porosity thickness product or -- and given  
10 an estimate of thickness a porosity of about .27 percent,  
11 which we use in many of modeling studies and so forth that  
12 we do, the source of that number is interference test ana-  
13 lysis.

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

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

24 But my point is that I agree completely  
25 with Mr. Elkins. We should also make a second calculation

1 and I will assure him that I do.

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

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

21 Now again, Mr. Greer will dig into this  
22 issue in detail and will present to you in his testimony  
23 later today or tomorrow the details of this study that he's  
24 made based largely on observed performance.  
25

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

8 So it's really a difference in percep-  
9 tion.

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

14 Q Let's turn to Exhibit page 13 --

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

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

19 Right. Yeah, first I want to talk about  
20 the qualitative observation, and that observation was that  
21 there was no oil bleeding from that core, it was completely  
22 clean of oil. There was some observed residual oil satur-  
23 ation at certain points but my major point is that my ob-  
24 servation was that here's this core of matrix. Now that  
25 core of matrix is brought out to atmospheric conditions.

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

6 Now based on, really, a lot on that per-  
7 ception of the core we concluded that whatever the perme-  
8 ability of that core is, it's simply not going to bleed oil  
9 to a fracture if it won't bleed oil even to the world at  
10 atmospheric pressure.

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

16 The laboratory analysis of permeability  
17 for that core are tabulated on page 14 and those tabula-  
18 tions are graphed on page 15 so we can kind of get a visual  
19 image of what the situation is.

20 The geometric mean of these tabulated  
21 permeability numbers is .0164 millidarcies but that's mis-  
22 leading, because 31 of those 51 samples have permeabilities  
23 less than .01 millidarcies even though they're entered as  
24 .01 here because that's the lowest permeability that this  
25 laboratory could make. So the mean that we get is a lower



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

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

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

10 I think it's important to observe that  
11 that cored well was a dry hole. That matrix is not produc-  
12 tive.

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

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

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

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

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

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

24                   The third difference is an important  
25 one, and that is in Mr. Hueni's modeling work he assumed

1 what we call pseudo-steady state, whereas I assumed what we  
2 call unsteady state. Now what do those words mean? Well,  
3 pseudo-steady state assumes that the pressure distribution  
4 is established throughout the matrix instantaneously and  
5 that we can characterize flow from that matrix simply by a  
6 difference of a pressure in the matrix and a pressure in  
7 the fracture.

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

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

18 So difference in assumptions leads to  
19 difference in calculated results.

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

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

25 Q Were cores from any other wells in the

1 field analyzed?

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

6 The other two wells that I'm aware of  
7 are the Mobil Lindrith B-38 and the Mallon Howard Federal  
8 1-11. In summary, both of these wells also have low perme-  
9 abilities which become even lower when corrected to in situ  
10 conditions, so I don't see any reason to change the opinion  
11 that matrix permeability is pretty low.

12 Q Have you prepared an exhibit which sum-  
13 marizes field operations which help you evaluate the dual  
14 porosity hypothesis?

15 A Yes, I have.

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

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

23 Q Let's go on to the dual porosity reser-  
24 voir hypothesis and look at the field observations then.

25 A All right, sir.

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

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

6                       Here's -- here's what the message is in  
7 summary. Eight wells in a 6-section area of Gavilan, eight  
8 wells which are amid some of the best wells in the field,  
9 are nearing depletion and despite the low pressure in the  
10 fractures in the area of these particular wells, it's about  
11 1000 pounds now lower than the original pressure in the  
12 system. These wells are declining rapidly and are nearing  
13 abandonment conditions and they're doing so because of de-  
14 clining capacity. It doesn't have anything to do with oil  
15 allowables. Their capacity is on a steep decline.

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

23                      Page 18 --

24           Q           That will show us the specific area in  
25 the Gavilan Mancos Pool in which you have found the 8 wells

1 in this 6-section area?

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

4 Q Let's look, so that we all know what the  
5 8 wells were, what portion of Gavilan are we dealing in  
6 now?

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

9 A Yes, that's right.

10 Q Is it this portion of the reservoir.

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

15 The 4 higher quality wells, obviously in  
16 the same general vicinity here, are identified with rectan-  
17 gles around the well name. These are the 8 wells in  
18 question.

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

1 issue?

2 A Yes, sir, I do.

3 Q Do you have an opinion on this interpretation?  
4

5 A Well, my opinion is that there is another possibility, an alternative explanation and one in  
6 fact is within the evidence I consider to be more probable.  
7

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

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

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

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

24 A All right, the shape of the pressure  
25 build-up test plot from the mid-, really late would be

1 a more accurate modifier, 1987 test of the Mobil Lindrith  
2 B-37 well is indeed similar to the shapes that character-  
3 ize build-up test plots from dual porosity reservoirs, as  
4 Mr. Weiss has very correctly observed.

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

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

11 Q Do you have any other explanations for  
12 the shape of this plot other than a dual porosity hypothe-  
13 sis?

14 A I think there's another very logical ex-  
15 planation. There are other phenomena and the one that I  
16 believe is responsible for the shape of this curve is call-  
17 ed phase redistribution in the wellbore. Basically what  
18 this is is that when we shut in a well for a build-up test,  
19 liquid in the wellbore will drop to the bottom of the well-  
20 bore and gas that's in that wellbore may rise to the top.  
21 Under certain circumstances that phase redistribution can  
22 lead to the same shape that was observed in the build-up  
23 test in the Lindrith B-37 Well.

24 Now, why do I believe that's a more pro-  
25 bable interpretation for this well? Well, because I have



1 clear evidence in this field that phase redistribution is  
2 occurring. Extreme cases of phase redistribution, when  
3 it's really severe, result in what we call a pressure hump  
4 and that pressure hump has virtually no other cause. Pres-  
5 sure humps are present in several test plots and probably  
6 to understand what these ideas mean and what this curve  
7 shape is all about we need to look at some graphs which are  
8 in this section of the booklet. I think we can start with  
9 page 26.

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

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

25 Now, this -- this curve does have some

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

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

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

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

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

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

3           A           Yes, sir.

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

7                       In extreme cases where a phase is redis-  
8 tributing you can get a high pressure gas column above an  
9 oil column which has dropped down below and the pressure in  
10 the wellbore can actually rise above the pressure in the  
11 formation and it could start pushing oil back in the forma-  
12 tion and it will continue to push until the pressure in the  
13 well is less than the pressure in the formation and then  
14 the pressure will start building back up again.

15                      Well, here, I think, is clear evidence  
16 of that occurring in this field and there are other exam-  
17 ples of this.

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

25                      But that's not really the essential

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

4 If you will refer with me back to page  
5 23 of the booklet, I'd like to give you some documentation  
6 for that assertion.

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

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

19 What I'd like to focus on now is simply  
20 conclusion number 4 in this paper, which is found on page  
21 25, and I have it completely underlined. What it says is  
22 this: "When the distortion caused by phase redistribution  
23 is not severe enough to cause a hump," like we saw in our  
24 second example well, "the characteristic shape of the pres-  
25 sure [buildup] behavior could be misinterpreted as that

1 from a dual porosity reservoir. The composite reservoir  
2 behavior could also be misinterpreted as an effect caused  
3 by the reservoir drainage boundary." Phase redistribution  
4 could make a test look like there was a boundary there.  
5 "When such a characteristic shape is displayed in a tran-  
6 sient test, more information should be sought about the  
7 reservoir geology, reservoir fluid phase behavior and fluid  
8 properties before a model -- ". That is, a basis for in-  
9 terpretation, an idealization of what that reservoir and  
10 well are like before you choose that model.

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

14 A Well, in summary on page 28 my conclu-  
15 sions are first that available core data indicates the  
16 matrix permeability is extremely low.

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

20 Now, again, that's subject to my percep-  
21 tion that the size of the fracture block is large.

22 The third conclusion is that actual  
23 field performance in an area of the field indicates that  
24 there is just no significant support from the matrix in  
25 that area in a number of declining wells that were good

1 wells a short time ago.

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

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

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

17 So I think it's the most probable ex-  
18 planation.

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

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

24 Mr. Carr, do you have any --

25 MR. CARR: No, I do not.

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

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

5  
6 (Thereupon a recess was taken.)  
7

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

10 MR. KELLAHIN: Yes, sir.

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

13 MR. DOUGLASS: Thank you, Mr.  
14 Chairman.  
15

16 CROSS EXAMINATION

17 BY MR. DOUGLASS:

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

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

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

5           A           I'm not aware of him being there when  
6 they took it out and laid it on the rig floor.

7           Q           Well, when you said there was no bleed-  
8 ing oil out of the core, what did you mean by that?

9           A           Well, when he observed the core there  
10 was simply -- simply no oil on the surface. I really don't  
11 know any more than that.

12          Q           Okay. You don't know when he observed  
13 it.

14          A           No, I don't.

15          Q           Well, let's assume that he observed it  
16 right when it came out and saw it immediately when it came  
17 out of the core barrel and there was no oil bleeding out of  
18 the core. Let's assume that, and let's assume, also, that  
19 you took a pressure core at the same time. Now, a pres-  
20 sure core is one that you actually core and you take out  
21 under pressure where you don't have the wellbore effect  
22 when you take out a conventional core, is that correct?

23          A           That's correct.

24          Q           And let's suppose that you were given  
25 the parameters in that pressure core and through the calcu-



1 lations, obviously, that you're very aware of, that you  
2 knew that there had to be oil coming out of that core that  
3 had been brought up out of the -- out of the well that Mr.  
4 Ellis observed, but you have this physical observation  
5 where there's no oil coming out of the core.

6 Under those circumstances would you  
7 question your calculations as to whether the data that  
8 you'd been given was correct as opposed to the actual ob-  
9 served information that Mr. Ellis had seen?

10 A That's --

11 Q Without looking at it?

12 A That's a pretty complicated question,  
13 you know. Even if we -- even if we say he did observe oil  
14 coming out of the core, we still have what I think is the  
15 larger issue of what is the -- what is the size of the  
16 fault block.

17 But back to the core itself, you know,  
18 my experience is that the poorer the rock the more likely  
19 it is to bleed and when it doesn't bleed at all, you really  
20 have a problem.

21 Q Well, my real question was wouldn't tend  
22 to believe Mr. Ellis more than you would your calculations  
23 if he'd actually seen that there wasn't any oil coming out  
24 of that core?

25 In other words, that would be an obser-

1       ved fact, wouldn't it?

2                   A           Yes, sir.

3                   Q           Now, the -- let us refer to page 3, if  
4       we could of your report here.

5                               Let's see if I observe -- see if I un-  
6       derstand this. This calculation came from a reservoir  
7       model, in fact, I assume 5 separate models, 5 tank calcula-  
8       tions, is that correct?

9                   A           5 tanks together in one model of the re-  
10      servoir.

11                  Q           5 tanks, and those tanks you've already  
12      gone over on the exhibit here that you've -- the blow-up  
13      here in the reservoir, is that correct?

14                  A           That's correct.

15                  Q           Would it be convenient to number those?  
16      I know you've got them -- West Gavilan, can we number that  
17      one 1? You've got next East Gavilan, number that 2. The  
18      pressure maintenance expansion area is 3. 4, being the  
19      west half of the west -- the injection project, not west  
20      half but the west part, excuse me. And the east part of  
21      the injection project being 5, as far as sectors are con-  
22      cerned. I think that might save a little time in having to  
23      -- did that -- would those be what somebody might call the  
24      5 cells of the model, is that what you meant?

25                  A           Yes, sir.

1           Q           And are all of your calculations, at  
2   least, that you made with reference to the various items of  
3   this report, including up through page -- I guess through  
4   -- maybe you ought to tell me, how many pages in this re-  
5   port are based on the use of that reservoir model that  
6   you've been talking about?

7           A           I believe through page 6.

8           Q           Through page 6. How about the items on  
9   page 10, 11 and 12?

10          A           Excuse me, you're right. They were also  
11   based on that model.

12          Q           Any more past 12 through the back of the  
13   book here, what about on pages 16, 16A, 16B?

14          A           No, not at all.

15          Q           So at least through page 12 the calcula-  
16   tions that you've made have been based on this reservoir  
17   model, is that correct?

18          A           Yes, sir.

19          Q           And what -- what you try to put in these  
20   reservoir models, I take it, is the observed data and the  
21   observed facts that you have, is that correct?

22          A           Yes, sir.

23          Q           And is that what you've attempted to do  
24   in this model that you have?

25          A           To the extent possible.

1           Q           And do I understand that based on that  
2 information that you put in that you found the pressure in  
3 the 4 and -- the 5 and 4 area here went down due to ini-  
4 tial production in that area, and the pressure over in 1, 2  
5 and 3 came down somewhat at the time, is that correct?

6           A           Yes.

7           Q           And then there was a point when injec-  
8 tion started in '67 or '68, somewhere along in there, that  
9 the pressure began to build-up in 4 and 5 and that's the  
10 top two lines that built -- instead of declining from about  
11 1967 or '68, actually increased during the entire period  
12 until, oh, until at least Gavilan was discovered in 1983,  
13 is that right?

14          A           That's correct.

15          Q           And that's what your model has shown  
16 you based on the data and information you put in there.

17          A           That's correct.

18          Q           Now, let's see what the observed facts  
19 are during that period of time.

20                      In this entire 4 and 5 area, what pres-  
21 sures did you have in the early time period? Are they  
22 shown on this exhibit, page 3?

23          A           In area 4 we have the first two crosses,  
24 the first -- first one quite early in Well L-11.

25          Q           All right.

1           A           And then a later one in from Well C-34.  
2           Q           The last one in C-34 down here. Those  
3           --  
4           A           Yes, sir.  
5           Q           - those are the only observed pressures  
6           that you have to put in your model at that time.  
7           A           That's correct.  
8           Q           And the pressure was going down.  
9           A           Yes, sir.  
10          Q           All right. Now, do you have a pressure  
11          in area 4 in 1988, or so?  
12          A           Not -- not a directly observed pressure,  
13          but what I have there around 1988 to try to get some feel,  
14          is a pressure taken from Mr. Greer's rainbow map.  
15          Q           Was that -- is that what that --  
16          A           That point is from the rainbow map simply  
17          taking an average position in the rainbow map but instead  
18          of using pressure as on that map, correcting to  
19          datum.  
20          Q           Okay. Observed that -- you consider  
21          that an observed pressure?  
22          A           It's based on an observed surface pressure.  
23          Q           You didn't use the C-34 pressure that  
24          was measured in -- in about 19 -- I think it says November  
25

1 of '87?

2 A No, sir.

3 Q If you had spotted it on there would it  
4 have been about in the same place that you have the plus?

5 A I don't know.

6 Q Well, let's see if I understand. You do  
7 consider the X you have over here, which is -- looks like  
8 it's in '88, to be an observed pressure though.

9 A Yes.

10 Q All right. If you connect up the obser-  
11 ved pressures in 4, in area 4, does it -- would it appear  
12 that the pressure would go down at one angle and then go  
13 down slightly all the way over to where the pressure is  
14 that you have with the other X?

15 A If you simply draw lines between points  
16 that's indeed the shape.

17 Q And those would be the observed pres-  
18 sures with lines between them.

19 A That's correct.

20 Q In your experience with dealing with  
21 this matter now, you've been -- you've been at it longer  
22 than I have, about 18 months, or so, 15 months, or so,  
23 maybe, in gathering the data and information who have you  
24 found to be the most knowledgeable people with reference to  
25 the operation of the unit over here, 4 and 5?

1 A The BMG people.

2 Q All right. Would that be Greer?

3 A Mr. Greer.

4 Q Been here all the time.

5 A Yes, sir.

6 Q You find him to be a good professional  
7 engineer?

8 A A superb professional engineer.

9 Q How about Mr. John Roe?

10 A Mr. John Roe is available for consulta-  
11 tion.

12 Q Has -- has he also been in that -- fami-  
13 liar with this unit operation during this entire period of  
14 time?

15 A I don't know about the entire -- surely  
16 not the entire period of time but familiar in recent years.

17 Q What if those two gentlemen had during  
18 the period of time from when injection started in '67 or '68  
19 had observed that the pressure was declining, not very rap-  
20 idly but maybe 10, 11 pounds a year, in areas 4 and 5 from  
21 the time injection started till 1986, 1987? Would you be-  
22 lieve them?

23 A I would like to see a basis for that  
24 statement but I have a great deal of confidence in both  
25 those gentlemen.

1           Q           They haven't furnished you any pres-  
2           sures during that period of time, have they?

3           A           No.

4           Q           As I understand it, Mr. Greer has a  
5           method by which he can which he can just look at the sur-  
6           face pressures out here and calculate the bottom hole  
7           pressures that he feels a lot confidence in.

8           A           Well, particularly now. I'm not sure he  
9           would have the same confidence in that in the past in that  
10          now he can do that in wells which are gas lift, or high  
11          gas/oil ratio wells, in which he feels confident that he  
12          has a wellbore full of gas and doesn't have to worry about  
13          an unknown liquid level as such.

14          Q           Mr. Roe in the -- in the March, 1987,  
15          hearing, that was a hearing that you attended?

16          A           Yes, sir.

17          Q           Let me show you what we've had identi-  
18          fied as Mallon Exhibit Fifty-one, which is an excerpt of  
19          his testimony from that hearing, Volume II, Page 214, and  
20          Mr. Humphries is asking the question.

21                    "QUESTION:   -- you had the best of all  
22          worlds, what would that curve look like?

23                    ANSWER:   For twenty years the unit main-  
24          tained a rate of pressure decline of about 11 pounds per  
25          year.



1 QUESTION: Which unit, the --

2 ANSWER: The Canada Ojitos Unit, with  
3 pressure maintenance, matching -- attempting to maintain  
4 reservoir pressure and produce the reservoir at a rate that  
5 approximately matched the gravity drainage rate, the rate  
6 of pressure decline, and again I said twenty years, I'm not  
7 sure how many years, but the rate of pressure decline was  
8 about 11 pounds a year."

9 Now does your pressure graph that you  
10 have used in your model, that your model has produced, does  
11 it show a pressure decline for about 20 years during the  
12 pressure maintenance project of about 11 pounds a year?

13 A No.

14 MR. DOUGLASS: Offer -- well,  
15 I don't know, let's -- yeah, let's have it -- I've already  
16 identified it as Exhibit 51.

17 Q Now, let me show you what I've asked to  
18 be identified as Exhibit Fifty-two, which is a portion of  
19 Mr. Greer's testimony in that same hearing, Page 90, Volume  
20 I, Mr. Greer testifies:

21 "Then in 1976 it picked up a steeper  
22 rate of decline and that, we think, was a consequence of  
23 our lowering our pressure maintenance gas injection.

24 Prior to 1976 the price of oil or gas  
25 was low enough that we over-injected in the reservoir and

1 by over-injected I mean we injected more gas than was  
2 necessary to just replace the oil. To maintain the pres-  
3 sure, of course, we had to over-inject as the oil falls  
4 down the structural dip, then it's necessary to increase  
5 the pressure in the gas cap in order to maintain the pres-  
6 sure in the producing wells. [But] even though we over-in-  
7 jected we still did not quite keep up with the pressure..."

8 Does your model indicate consistency with  
9 what Mr. Greer testified to about not being able to keep up  
10 with the pressure decline during this period of time?

11 A No there's a difference.

12 MR. DOUGLASS: We'll offer 51  
13 and 52, Mr. Chairman.

14 MR. LEMAY: Without objection,  
15 51 and 52 into the record.

16 Q Let me show you what we've identified as  
17 Proponents Exhibit Fifty-three in this proceeding.

18 On Fifty-three the yellow has -- has  
19 that yellow line been correctly connected in the manner  
20 that I visited with you about earlier as far as being --  
21 connecting the points?

22 A Yes, sir, it has.

23 Q That yellow line appears to be substan-  
24 tially below the pressure that you have found in 4 and 5,  
25 is that correct?

1           A           That's correct.

2           Q           Now, I know that you don't have any way  
3 of measuring, but I'll show you Exhibit Twenty in this  
4 hearing, and I believe the pressure decline that I'm going  
5 to be visiting with you about was also shown exactly the  
6 same on Exhibit Nine in the March '87 hearing, which --  
7 excuse me, March '88 hearing, which you attended, and I'll  
8 ask you if it appears that the pink line shows approximate-  
9 ly the same pressure decline as shown on Exhibit Twenty  
10 that Mr. Hueni has put into the record? The pink line on  
11 the curve.

12          A           Yes, it's qualitatively the same.

13          Q           And his line would be slightly below the  
14 yellow line that you've drawn and both the yellow and the  
15 pink line are substantially below what your reservoir model  
16 shows with reference to areas 4 and 5.

17          A           That's correct.

18          Q           Now, at the March '88 hearing did you  
19 also use this same reservoir model that you have here, per-  
20 haps not to the extent, but -- or -- well, strike that.

21                       Did you use a reservoir model in the  
22 March '88 hearing to make some calculations?

23          A           Yes, I did.

24          Q           Was it one that extended from the east  
25 through area 5, 4, 3, and 2? I'm not sure whether it went

1 into 1 or not. Did it?

2 A As I recall, I don't remember where it  
3 ended up.

4 Q So it -- but it certainly went across  
5 the boundary here, the current boundary of what the -- of  
6 what we've been talking about as the Gavilan and the West  
7 Puerto Chiquito, is that correct?

8 A Yes, sir.

9 Q And so that model would reflect the  
10 pressure from the beginning of time across that boundary,  
11 is that correct?

12 A Oh, no, it was not intended to do that,  
13 not at all.

14 Q Well --

15 A It was not an attempt to match history.

16 Q Well, didn't you testify and didn't you  
17 match history for this -- for this 4 and 5 area then?

18 A Not with that model. That was -- there  
19 were really two models presented in that -- in that hear-  
20 ing, one of which was a modeling of qualitatively the good  
21 that could be done with a gas plant or taking produced gas  
22 to a plant; the second of which was a demonstration model  
23 showing the effect of gravity drainage.

24 Q Would either one of those models have  
25 matched this early time history and give us a pressure

1 across the area that we're dealing with here?

2 A There was no attempt to match history.  
3 To match history you have to try to put in the properties  
4 as they vary with position across the model, and so forth.  
5 There was no attempt to do that with that model work.  
6 Those were to demonstrate concepts.

7 Q Well, I'll offer Exhibit -- offer Fifty-  
8 three, Mr. Chairman. I may have not offered Fifty-one and  
9 Fifty-two altogether with Fifty-three. Offer all three  
10 together.

11 MR. LEMAY: Without objection  
12 they'll be accepted into the record.

13 Q Let me show what I'm going to ask, for  
14 the record, to be identified in the record as Exhibit  
15 Fifty-four.

16 On Exhibit Fifty-four in red has been  
17 placed the simulation output for the pore volume average  
18 pressure for the simulation study that you put in in March  
19 of 1988. Does that appear to be the proper pore volume  
20 average pressure that you had in your model at that time?

21 A Oh, I'll take your word for the fact  
22 that that's what it said, but again I'm going to say there  
23 was no attempt to match history by putting in the kinds of  
24 things in that reservoir, and particularly trying to --  
25 trying to look at the special distribution of properties,

1 and so forth.

2 Q Well, it looks at the first part of that  
3 that you were able to match the -- even better in that  
4 model than you are in this one the original measured pres-  
5 sures that you had at that time.

6 A Well, it may do that but that was not  
7 a purposed of the model.

8 Q And doesn't it also show that the pore  
9 volume average pressure follows essentially the same line  
10 Mr. Hueni drew, the same line on his extrapolation there,  
11 and the same line if you actually connect up the points in  
12 the areas 4 and 5 on the map?

13 A The lines are about the same place, yes.

14 Q Now wouldn't the observed facts of pres-  
15 sure, the observed facts of Mr. Greer and Mr. Roe and your  
16 previous work, and Mr. Hueni's work in this area, all indi-  
17 cate to you that the pressure in the areas 4 and 5 did not  
18 do what you show on your model?

19 A No, it doesn't, because if you put in  
20 more than the take out pressure's going to go up.

21 Q Well, it may not necessarily have to go  
22 up but it may have to go some place, right?

23 A Okay.

24 Q So if the pressure is going down it  
25 means it may be going somewhere else.

1           A           I'll consider that as a hypothesis.

2           Q           In other words, the observed facts would  
3 lead you to the conclusion, just like Mr. Ellis' observed  
4 facts, was that they overcome and tell you that your model  
5 is really not telling you what took place in that reservoir  
6 during the twenty years, isn't that correct?

7           A           I'm not sure that we have any observed  
8 facts that say that, Mr. Douglass. I see no observed pres-  
9 sures below the line that I projected in my model study in  
10 this time period from '71 to '84 or '85. I don't have any-  
11 thing.

12          Q           You have the sworn testimony of Mr.  
13 Greer and Mr. Roe, don't you?

14          A           Yes, but I, you know, I would like to  
15 study the context. I realize what you say here but are we  
16 talking about averages? Did we take a pressure twenty  
17 years ago and a pressure twenty years later and look at the  
18 total change without worrying about what had been going on?  
19 I just don't know the context of that statement.

20          Q           Did you go into that kind of detailed  
21 examination of Mr. Ellis about what he saw on the bleeding  
22 core?

23          A           No.

24          Q           Is one of the things that happens to  
25 cores when they're brought out of wells is that they're

1 washed?

2 A Yes.

3 Q Those old roughnecks don't like that mud  
4 on the floor, do they?

5 A Right.

6 Q Is that a possible explanation of why  
7 Mr. Ellis didn't see any oil on the core, that it has al-  
8 ready been washed by the time he saw it?

9 A Well, it might be, but, you know, it was  
10 more than just a visual inspection of the outside of the  
11 core. It was a look at a lot of that core material.

12 Q In your model have you calculated what  
13 the, with 270-foot fracture spacing, have you calculated  
14 how wide the fractures are in that model?

15 A Maybe I don't understand the question.  
16 To me the answer to the question I thought you asked would  
17 be 270 feet, but --

18 Q Well, that's -- this is between the  
19 fractures.

20 A Yes, sir.

21 Q All right, what is the distance within  
22 the fracture; in other words, the fracture width?

23 A Oh, goodness, I don't know.

24 Q Is it something you could calculate out  
25 of your model?



1 A No.

2 Q Nobody's been able to calculate that.

3 A No.

4 Q Does your model have a porosity in it?

5 A Yes.

6 Q What was the porosity?

7 A Let's see, if it's summarized on our  
8 data here. 0.439. What we tried to do here was use to the  
9 extent possible, properties that Mr. Hueni used, focusing  
10 on those areas where we felt we ought to look to see wheth-  
11 er there would be a significant (unclear), so 0.439, but  
12 because Mr. Hueni used it.

13 Q Now that's a percent, that porosity, is  
14 that correct?

15 A Yes.

16 Q So it would be 0.00439?

17 A Yes. It is a fraction.

18 Q Yes, sir. Now, I believe I didn't un-  
19 derstand you correctly, you said these fractures were 270  
20 feet long?

21 A In this particular model and only be-  
22 cause that's what Mr. Hueni used, that I modeled the same  
23 size fractures.

24 Q He used 270 feet apart fractures in his  
25 model?

1           A           Yes, that was my understanding of the  
2 (not clearly understood) of his computer output. With  
3 the -- let me -- let me say, that with the pseudo steady  
4 state formulation you can have all sorts of combinations of  
5 fracture size and permeability, you know, that can go to-  
6 gether in any combination, but what we did, still, is work  
7 with a 270 fracture and the permeability that would go with  
8 that in his model.

9           Q           Well, I may have misunderstood. I  
10 thought you said that's what Mr. Greer said.

11          A           No, no, no. If I said Mr. Greer, I mis-  
12 spoke. What I did is look at the properties that Mr. Hueni  
13 used in his modeling effort and said, okay, if I change the  
14 things that I think are particularly important, will I get  
15 a significantly different result, and the one that really  
16 matters, of course, is permeability.

17          Q           Well, let's see, if the fractures, if  
18 they were 270 feet apart, they might not go through the re-  
19 servoir exactly at that, but that would be the -- is that  
20 the way the model would look at it, being something like  
21 that?

22          A           The way that we actually did this model  
23 with what we call a slab type model. Total thickness of a  
24 slab is 270 feet with the fracture in it, so we didn't use  
25 the geometry that you did. I used a method of modeling

1 which is proposed by a gentleman named (unclear) in petro-  
2 leum literature, and he said if you model fractures in a  
3 slab that's equivalent to many other shapes within the  
4 reservoir, notwithstanding what's in the model, it's a  
5 slab. The fracture is horizontal.

6 Q The fracture is horizontal.

7 A The fracture is horizontal.

8 Q You have reservoir rock above and below  
9 it, then?

10 A That's correct. The fracture is hori-  
11 zontal. That's equivalent to blocks in the reservoir and  
12 (inaudible).

13 Q In other words, that would be a fracture  
14 and then you have reservoir rock and at 270 feet does it  
15 have another --

16 A Yes, it has another fracture.

17 Q -- another fracture above and in between  
18 here is where you say that there is essentially no porosity  
19 in that rock.

20 A That's right. That's our matrix.

21 Q And in the -- in the -- in the fracture  
22 itself it has a porosity of 0.00439, or 0.439 percent.

23 A Correct.

24 Q All right, sir. And if you were going  
25 to determine -- would that mean that in this direction

1 you've got half of that porosity or each direction is half  
2 the porosity?

3 A Yes, sir.

4 Q Okay, that would be what, 0.002?  
5 0.0-0-2-2?

6 A Okay.

7 Q Is that right?

8 A Yes, sir.

9 Q All right, sir. Well, now, let's see,  
10 you've got 270 feet, as I understand the distance here. If  
11 I wanted to find out how -- how much distance I'd need in  
12 that fracture to hold that kind of porosity in that area,  
13 that would be -- if I want to convert that to inches, I'd  
14 multiply it by 12 inches, wouldn't I?

15 A Okay.

16 Q Okay. And then I've got a porosity here  
17 of 0.0022, is that right?

18 A Yes, sir.

19 Q Now wouldn't that give me the fracture  
20 width?

21 A Yeah, the fracture width used in this  
22 idealization of what might be a block or something else.

23 Q Do you have a calculator on --

24 A If you'll give me your number, I'll pro-  
25 bably accept it.

1 Q Well, I'm not sure I've got the right  
2 number because my multiplier only used 0.002.

3 A Okay.

4 Q And using in 0.002 it comes out to 6.5  
5 inches is that fracture width.

6 A Okay.

7 Q Do you think the fractures in this re-  
8 servoir are 6-1/2 inches wide?

9 A No, but I -- again, this is an ideali-  
10 zation. You know, we can also vary the permeability within  
11 that fracture and get a fracture flow capacity and that's  
12 what matters.

13 Q Well, that fracture flow capacity could  
14 be affected by oil flowing out of this rock up here that  
15 you say would not flow, couldn't it?

16 A Would the fracture flow capacity be af-  
17 fected by the oil? I'm not sure I follow.

18 Q Well, let me -- let me go back to an-  
19 other question.

20 Let me ask you in your model here, as I  
21 understand it, that you relied on there being essentially  
22 no oil that would contribute to production from the frac-  
23 ture, is that right?

24 A Oil in the matrix with the permeability  
25 of the four zeros, or the five, or whatever.

1           Q           And your data in that regard is based on  
2 the -- at least in part, and maybe a major part, on this  
3 core taken out of the 3-15, is that correct?

4           A           That's correct. That's correct.

5           Q           And I believe you emphasized in your  
6 direct that it was dry hole?

7           A           Well, that's an overstatement. It's a  
8 marginal well, 5 barrels per day, or perhaps slightly more,  
9 so perhaps I overstated it, but it's a very poor well.

10          Q           Oh, it is a poor well. Well, then, if  
11 it's out here in one of these tight fracture blocks that  
12 Mr. Greer says are an acre or so, then that matrix is pro-  
13 ducing out there, isn't it?

14          A           Depends on whether that well's been  
15 hydraulically fractured, which is virtually essential to  
16 get production in this area.

17          Q           Well, I understood Mr. Greer's testimony  
18 and really I wasn't at the first two hearings, I understood  
19 him to testify that you had to essentially frac all these  
20 wells and you couldn't get any production before you did.

21          A           That is my understanding, too. You have  
22 to hook up with the natural fractures; the odds of hitting  
23 one with drilling are, you know, above zero but not much.

24          Q           Well, the odds are sure a whole lot  
25 greater when you've got these fractures 270 feet apart than

1 you do when they're 6 inches or 12 inches or 2 feet apart,  
2 don't you?

3 A The odds are less or greater?

4 Q Well, less. The odds are greater of  
5 hitting a fracture the closer they are together.

6 A Yes, sir, I agree with that.

7 Q And when you want -- when you put them  
8 out 270 feet apart, you're really stretching the odds out  
9 about whether you're going to get anywhere close that you  
10 can even frac into one, aren't you?

11 A Yes.

12 Q Well, let me get back to 3-15, that that  
13 well is in one of these tight blocks that you -- that Mr.  
14 Greer described, and you're producing oil from the matrix,  
15 aren't you?

16 A I don't know whether that well has been  
17 hydraulically fractured.

18 Q Well, let's assume it has. Let's assume  
19 it has been fractured, just like all the rest of the wells.  
20 Aren't you producing well out of that well out of the mat-  
21 rix?

22 A My answer would be no.

23 Q Now, let me visit with you about this  
24 boundary protection plan Mr. Greer has.

25 A Yes, sir.

1           Q           Now the boundary protection plan that  
2 Mr. Greer has is in part the restricted rates, is that  
3 correct?

4           A           I really shouldn't speak for Mr. Greer.  
5 The general thrust of what he's explained to me, and this  
6 is very much subject to correction by him when he testi-  
7 fies, but I think the general thrust is a testing program  
8 to assure comparable pressures at offset wells across the  
9 boundaries.

10          Q           But the boundary protection program, I  
11 believe, that you indicated, has been in effect since Jan-  
12 uary 1, '87.

13          A           The protection plan in effect since Jan-  
14 uary is not a formal plan. Mr. Greer will propose a formal  
15 plan administered. The current way he perceives that he  
16 can protect the boundary is simply to drill a well offset-  
17 ting another well and try to not have migration either way.

18          Q           Well, did you understand the boundary  
19 protection that's been in since 1-1-87 keeps oil from  
20 moving from area 3 to area 4, I mean area 2 and 1?

21          A           That's the objective of offsetting  
22 wells.

23          Q           Nothing in that boundary protection plan  
24 keeps the oil from moving from area 2 into area 3, though,  
25 is there?



1           A           There's nothing to assure the oil won't  
2 move the other way, either, Mr. Douglass. It's simply an  
3 attempt to offset and protect the unit.

4           Q           My question was there's nothing in that  
5 boundary protection plan of 1-1-87 that keeps the oil  
6 moving from area 2 to area 3?

7           A           There is nothing in the plan to keep oil  
8 from moving either direction except an attempt to produce  
9 offset wells.

10          Q           Mr. Lee, let me ask you to turn to page  
11 16B.

12                   Now I understand your concept of this  
13 reservoir to be that there's just practically these major  
14 fracture systems out there and no contribution from the  
15 matrix to those fracture systems.

16          A           That's probably some overstatement but  
17 there are clearly microfractures, these are observed; they  
18 have some contribution. It's just I don't see 80 percent  
19 of the oil in a system like this. I would see a very small  
20 fraction.

21          Q           What percentage of oil do you think is  
22 what we've been calling a major fracture system or what  
23 you've called a major fracture system?

24          A           Well, it's, you know, I think for -- for  
25 talking purposes virtually 100 percent, with a minor con-

1       tribution --

2               Q               Okay, will you --

3               A               -- from these microfractures.

4               Q               Well, you and I are in agreement now  
5 with what your position is, that one, you think there is  
6 essentially no contribution from the matrix and essentially  
7 100 percent of the recoverable oil from the major fracture  
8 system.

9               A               Essentially, with that qualification.

10              Q              Now, on 16B do I understand looking at  
11 16B that it shows that when you get to zero relative perme-  
12 ability as far as oil is concerned, that you've got a 40  
13 percent gas saturation.

14              A              Yes, sir.

15              Q              Does that mean that in this major frac-  
16 ture system that we've got here, that when you get down to  
17 zero permeability to oil you should have a 40 percent gas  
18 saturation, or when you get at 40 percent gas saturation  
19 you're not going to have any movement of oil out of the  
20 major fracture system?

21              A              Yes.

22              Q              And left in that fracture system with  
23 the 40 percent gas is going to be 60 percent of something  
24 else.

25              A              Right.

1 Q And that some thing else is -- what's  
2 the water saturation?

3 A Oh, pretty small in the fractures.

4 Q 10 percent?

5 A Perhaps.

6 Q Is that high or low, I don't know?

7 A I don't know.

8 Q Well, if it was 10 percent, then we're  
9 going to have 50 percent oil saturation in that fracture.

10 A Okay.

11 Q In this reservoir that we're dealing  
12 with, with that kind of characteristics, what's to keep you  
13 from producing down to depletion and then waterflooding  
14 that fracture to get that 50 percent oil saturation?

15 A Nothing.

16 Q Do you have your input data and your  
17 model printout for the exhibits that you've given us here?

18 A Yes, sir, I do.

19 Q May we have a copy of it? I know you  
20 can't give it to us right now but when you can?

21 A I probably can. What specifically would  
22 you like?

23 Q All of it.

24 A Well, what are you calling (unclear)?

25 Q Well, I think the computer printout

1 shows input and what it was in various stages.

2 A Yeah, but I mean, you know, we've had  
3 several different calculations; the tank model?

4 Q Yes.

5 A The unsteady state matrix flow?

6 Q Yes.

7 A Okay.

8 Q You got any more?

9 A I think that's all.

10 Q Hope it is. In your tank model did you  
11 have a gas cap?

12 A Not initially.

13 Q Was there a gas cap initially in this  
14 reservoir?

15 A Virtually impossible to determine.

16 Q Do you know what volume of gas that you  
17 had in the -- you started out with no gas cap.

18 A Started out with no gas cap.

19 Q Okay. Have you -- have you prepared a  
20 report or have you (unclear) a televiewer log with refer-  
21 ence to the core that Mobil took?

22 A I've heard testimony on the televiewer  
23 log.

24 Q And they -- indicating that there were  
25 fractures 2 to 4 inches apart?

1           A           They indicated that there were fractures  
2 and the judgment is does that constitute a major fracture  
3 or does that constitute a local phenomenon which quickly  
4 fizzles out.

5           Q           You've, on your Exhibit Two, you've cal-  
6 culated what -- what movement of reservoir barrels occurred  
7 in a period of June 30, '87, to February 23, 1988, is that  
8 correct? Is that 24,000 barrels?

9           A           Yes, sir.

10          Q           If the pressure in the 4 and 5 area had  
11 been approximately to this pressure level that's shown by  
12 connecting up the points off the -- in this area that you  
13 have on your Exhibit One, could someone calculate, using  
14 Mr. Powell's maps, as you did, the movement of fluid from  
15 1, 2 and 3 into area 4 and 5 when the pressure equalized  
16 along what we've called the proposed boundary?

17          A           I think I understand the question but  
18 let me ask you to ask it again.

19          Q           Sure. My question is that if you use  
20 the pressure from actual measurements in 4 and 5 and use  
21 Mr. Powell's maps, could you make a calculation in the  
22 other direction that you've made along the boundary, along  
23 the same boundary that you'd made?

24          A           Oh, the answer is no. The -- the as-  
25 sumption on which my calculation was based was that there

1 is no pressure change and that's based on Mr. Powell's  
2 observation.

3 The only other, in the other areas there  
4 was an observed pressure change.

5 Q Well, if you would be able --

6 A So, you know, so there;s expansion of  
7 fluids and things like this that have to be taken into ac-  
8 count, whereas I could just look at migration equals injec-  
9 tion less production.

10 That's why I went to the tank type bal-  
11 ance, to handle the more complicated situation in which  
12 pressure is changing.

13 Q With reference to those 624,000  
14 reservoir barrels that you can't account for in your calcu-  
15 lation, do you think they could have gone to the same place  
16 that Mr. Greer and Mr. Roe saw -- realized they were going  
17 to when the pressure declining even though they were over-  
18 injecting?

19 A I think that oil went across that alleg-  
20 ed barrier.

21 Q I understand you think that's where it  
22 went but it also could have gone in the same place where  
23 the gas went or the pressure went during the 20 years that  
24 Mr. Greer and Mr. Roe said the pressure was declining in  
25 this 4 and 5 area even though they were over-injecting.

1                   A               Well, this is a hypothetical place.

2                                   MR.     DOUGLASS:     Pass     the  
3     witness.

4                                   MR.     LEMAY:     Mr. Pearce?

5                                   MR.     PEARCE:     Nothing, Mr.  
6     Chairman.

7                                   MR.     LEMAY:     Mr. Lopez? Mr.  
8     Lund?

9                                   MR.     LUND:     Yes, sir, please.

10

11                                   CROSS EXAMINATION

12     BY MR. LUND:

13                   Q               A     quick     question, Dr. Lee. The exhibit  
14     that you passed out on Monday, the 7-page exhibit, were you  
15     aware that this was going to be an exhibit produced in this  
16     hearing?

17                   A               Yes.

18                   Q               Thank you.

19                                   MR.     LEMAY:     Additional ques-  
20     tions? Mr. Chavez.

21

22     QUESTIONS BY MR. CHAVEZ:

23                   Q               Dr. Lee, on your Exhibit Number One,  
24     page 2, how far north and south do these tank models go  
25     beyond the area that's mapped on page 2?

1           A           Actually the tank lengths are only 8  
2 miles in the model but what we do is actually put every --  
3 every well that's between these, let's call them vertical  
4 boundaries, put them in the tank, even though there may be  
5 more than 8 miles of production in some specific areas. We  
6 just include that production in the tank. So I hope I'm  
7 clear when I answer 8 miles long with in some cases wells a  
8 little bit outside of that put in the tanks.

9           Q           Do you agree with Mr. Greer's statement  
10 from early hearings that the reservoir, at least the West  
11 Puerto Chiquito Mancos Pool, has greater permeability in  
12 the north and south direction than in the east and west  
13 direction?

14          A           Oh, I think there's very substantial  
15 evidence that that's so, at least in some local areas, such  
16 as in the current pressure maintenance area.

17          Q           In your studies did you take a look at  
18 wells depleted further south in the pool, for example, the  
19 Amoco well that's completed in Section 25 of Township 24  
20 North, 1 West?

21          A           I was aware that activity like that was  
22 going on but I really hadn't looked at it there.

23          Q           Could you look at page 10 of your Exhi-  
24 bit 1?

25          A           Yes, sir.



1           Q           At what point did Mr. Greer begin over-  
2 injecting in the pressure maintenance project? Would you  
3 identify that on that map?

4           A           To identify that I'm going to have to  
5 look at page 3, I believe it is.

6                       I'm going to look at page 3 because on  
7 page 3 we will see a time at which the pressure in the en-  
8 tire reservoir clearly is beginning to increase, meaning  
9 more injection and withdrawals. That time is about 1972,  
10 in that range. So, 1972, you could put a tic mark on page  
11 10.

12           Q           Did you verify that date with the injec-  
13 tion and producing volumes in the pressure maintenance pro-  
14 ject?

15           A           Yes. You know, that's -- that's really  
16 what caused the turnaround in the graph on page 3, and that  
17 was based on observed and reported injection and production  
18 volumes.

19                       Yes, I checked it several times.

20           Q           If you were to draw a line on the zero  
21 point on the left side of your graph on the Y scale and  
22 extend it -- start on the left part of the scale and extend  
23 it all the way to the right, at what point would you find  
24 that the pools may be what we call balanced so that the --  
25 the oil had been perhaps returned back to the pools the way

1 it was originally found?

2 A Well, if you take this graph literally,  
3 and I think I've drawn such a line, and it's about 1977,  
4 and I would caution that I think about all that we can  
5 really hope for here is an indication of direction and if  
6 anything, the exact time period and magnitude I think would  
7 be pushing this sort of modeling well beyond its limita-  
8 tions.

9 Q Could you be within one year as far as  
10 --

11 A Oh, I think we ought to be within, you  
12 know, within plus or minus two years either direction.  
13 It's a reasonable probability.

14 Q Do you recall when the discovery well  
15 first started producing in the Gavilan Mancos Pool?

16 A 1982, I believe, or late '81.

17 Q And if you identify that point on your  
18 graph, what would be the cumulative amount of oil which  
19 would have migrated towards the Gavilan Mancos Pool at that  
20 time?

21 A Again taking these numbers literally  
22 about 200,000 barrels, but I would caution not to (not  
23 clearly heard.)

24 Q Do you find that's in contradiction with  
25 the original bottom hole pressures that were found in the

1 Gavilan Mancos Pool which were below what would have other-  
2 wise been virgin reservoir pressures?

3 A I don't know about those original pres-  
4 sures in the Gavilan Mancos Pool. The first one was sub-  
5 stantially lower even than the second one and the second  
6 one came several years later, you know, so maybe we have  
7 maybe a data problem. The first one was the Gavilan 1.  
8 What I -- what I have found about that well is it was a  
9 poor well with low permeability and the significance of  
10 that is that in this heterogeneous reservoir there may be  
11 wells in the area which are, you know, given a little bit  
12 of production and it may take forever to build up; not re-  
13 ceiving pressure support for wells later; you know, there  
14 are just all kinds of potential local anomalies.

15 But again I would point out the signifi-  
16 cant fact that if we take the Gavilan 1 literally, you  
17 know, the Rucker Lake Well was quite bit higher later. So  
18 I don't know, I probably am not answering your question,  
19 but those, you know, those two pressures were lower than  
20 the discovery pressure there, if either of those is a dis-  
21 covery pressure, is lower than the discovery pressure in  
22 the Canada Ojitos Unit. All the pressures in the unit have  
23 been high with this over-injection.

24 Q Well, looking at 1987 on your page 10,  
25 how much oil, cumulative, would have been moved to the

1 Gavilan Mancos Pool, say, at the beginning of 1987, accord-  
2 ing to that graph?

3 A 1,600,000 barrels, perhaps.

4 Q And if at the beginning of 1987, or  
5 let's say the end of 1986, the Gavilan Mancos Pool had pro-  
6 duced 3,000,000 barrels; a little over half of that you  
7 would have attributed to migration from the expansion area  
8 or from the West Puerto Chiquito Mancos Pool?

9 A Oh, I don't think that's necessarily  
10 true at all.

11 In the first place, I don't think we  
12 produce necessarily a significant fraction of that which  
13 migrates.

14 MR. CHAVEZ: Thank you, that's  
15 all.

16 MR. LEMAY: Thank you. Addi-  
17 tional questions of the witness? Commissioner Humphries?

18  
19 QUESTIONS BY MR. HUMPHRIES:

20 Q Dr. Lee, Mr. Hueni's theory, I don't --  
21 I guess his conclusions had to be derived or his informa-  
22 tion led him to the conclusion that there is a dual poro-  
23 sity system there and that the barrier exists. Any you find  
24 just the opposite, that there is no dual porosity barrier  
25 -- I mean no dual porosity system and there's no barrier,

1 is that correct?

2 A Yes, sir, that's -- those are my con-  
3 clusions.

4 Q I like to think that most things make  
5 some sense, with the possible exception of me having run  
6 for office. I like to think that I have some common sense  
7 and it's hard for me to disregard Mr. Hueni's idea that a  
8 difference in pressure in the fracture system would lead to  
9 some contribution from the surrounding material.

10 You don't believe that a matrix exists  
11 in any form or that it's a very limited matrix?

12 A I'd say a very limited matrix, and I  
13 think you're on to the fundamental reason. Certainly if  
14 there were a matrix with high enough permeability, whatever  
15 high enough is, and there were a pressure difference, that  
16 matrix would at least leak some fluid into the fractures.

17 I think where we have a difference in  
18 perception is on whether there is a matrix with permeabi-  
19 lity present in this pool and based on the core data that  
20 I've seen and the size, the apparent size of the fault  
21 blocks, I'd say that whatever oil can come in is very lim-  
22 ited in amount.

23 Q I think it was my term. but the concept  
24 of a one-way movement is a little hard for me to under-  
25 stand. I know water kind of has a tendency to go one way

1 and that's downhill. They tell me it moves uphill for  
2 money but I'm not sure that that's necessarily true in this  
3 case. How -- how could even a dual porosity system not,  
4 given a 3-dimensional fracture system, it must pass back  
5 and forth through the matrix if there is matrix contribu-  
6 tion, how could that only work one way, or is -- I realize  
7 your contention is different but you might help me to un-  
8 derstand that; nobody else has been able to. I understand  
9 the theory of the reduced pressure leading to contribution  
10 to the fracture system. I don't understand why they can  
11 only be one direction.

12 A Well, the one direction that I think  
13 we're talking about, please correct me if I'm off base on  
14 the concept, we're talking about the tendency of oil to  
15 imbibe back into the fracture system and then not be fur-  
16 ther produced. I think the analogy that's been used of a  
17 sponge is a good analogy. If you put a sponge in water it  
18 will imbibe that water. Now you can apply force and get it  
19 out but if you don't do anything it's going to stay there  
20 and it may take, you know, the smaller the spaces in the  
21 sponge the harder you may have to push to get it out. You  
22 might have tiny spaces.

23 In a reservoir there may just not be  
24 enough force, namely difference in pressure in the matrix  
25 and the fracture, to produce it back out, but there, on the

1 other hand, there may be. It may not be a one-way phenom-  
2 enon. It depends on the force available to push that oil  
3 back out.

4 Q I think Mr. Chavez has asked this same  
5 question but I want to make sure I understand it.

6 Is the permeability variation that you  
7 perceive consistent and parallel along the alleged barrier?

8 A I think I understand the question. Let  
9 me -- I'll try to --

10 Q How far north and south do you see it  
11 going and is it consistently parallel to that barrier, be-  
12 cause that's what the tanks sort of indicate?

13 A Mr. Greer has described in previous tes-  
14 timony what he calls permeability plateaus with -- with re-  
15 ductions in permeability at various levels, but on a given  
16 level very high permeability going north and south in this  
17 field. You know, I don't know how high but very high per-  
18 meability north and south, and perhaps rather an excellent  
19 permeability east and west, and then perhaps some geologic  
20 feature which I don't think the term "barrier" is appro-  
21 priate, if you'll forgive me, but at least a reduction in  
22 permeability, across which there is a significant drop in  
23 pressure and then another permeability plateau, again  
24 pretty high east/west but probably a little bit higher  
25 north/south with essentially equal pressures for many miles

1 north and south.

2 Am I getting at your question?

3 Q Does that -- would that permeability --  
4 what's a good word to use, pressure differential, or perme-  
5 ability variation, does that extend to the boundaries of  
6 the reservoir, perhaps beyond the pool?

7 A I don't think it extends as regularly as  
8 the boundary but that permeability variation of a sort ex-  
9 tends throughout the pool; for example, as I've observed  
10 earlier, in Gavilan there are currently very substantial  
11 pressure gradients within Gavilan that even though we have  
12 all, both sides, always refer to Gavilan being excellent  
13 pressure communication.

14 What does that say? That says some, at  
15 least some local areas have much reduced permeability  
16 offering considerably more than the usual resistance to  
17 flow would cause this gradient. So, you know, we have --  
18 we have heterogeneities through out the pool, although not  
19 necessarily of the same kind in all places in the pool.

20 Q I think Mr. Douglass has asked you about  
21 a fairly significant discrepancy between Exhibit Three that  
22 you had used earlier and Exhibit Fifty-one and Fifty-two  
23 from an earlier hearing.

24 Would you briefly explain that discre-  
25 pancy as far as you see it, the one where you're indicating



1 essentially no pressure drop and the other where Mr. Greer  
2 and Mr. Roe both indicated that there had been some pres-  
3 sure drop over a long period of time?

4 A Well, I don't know which of the simula-  
5 tions Mr. Douglass was showing me the --

6 MR. DOUGLASS: I think page 3.  
7 He said Exhibit Three.

8 Q Excuse me, page 3 and exhibit --

9 MR. DOUGLASS: Exhibits Fifty-  
10 one and Fifty-two.

11 A Okay, you were not referring to the pre-  
12 vious modeling work that I had done but to the testimony of  
13 Mr. Roe and Mr. Greer, a comparison of that to page 3?

14 Q Yes, sir, where one indicates a protrac-  
15 ted decline, I think it said probably 11 pounds per year,  
16 and the other -- other doesn't seem to indicate that.

17 A Yeah. I've not seen those transcripts  
18 before and I don't know the context. I see the possibility  
19 that in the case of the 11 psi per year that that's taking  
20 a pressure at some time and a pressure at a later time, and  
21 perhaps not taking into account what happened in between.

22 I don't know that but seems like that's  
23 a possibility. Certainly if you look at current pressures  
24 in the pool, they are dropping substantially below pres-  
25 sures some years ago, even though they may have risen in

1 the intervening time.

2 So, you know, I just don't know the  
3 context of the statements.

4 Q Yesterday Mr. Elkins made a comment and  
5 I believe he said that he wasn't extremely familiar with  
6 the West Puerto Chiquito Pressure Maintenance Project, but  
7 he said it appeared that the production rates were exceed-  
8 ingly low, and you've indicated that you are fairly fami-  
9 liar with the West Puerto Chiquito Pressure Maintenance  
10 Project and perhaps the whole Canada Ojitos Unit.

11 How would you respond to that? I mean  
12 that was kind of a question in my mind. Why would its  
13 production rates be exceedingly low if it was not some  
14 reservoir management?

15 A It is. It's very specifically for re-  
16 servoir management reasons.

17 Mr. Greer has studied the possibilities  
18 offered by gravitational segregation; the tendency of gas  
19 when it's in original solution to move upward and oil to  
20 move down.

21 If you go slowly, produce slowly, with-  
22 draw slowly from your well, the gas has time to get up and  
23 get away from the oil and you can produce low gas/oil ratio  
24 wells for a long period of time.

25 If you produce more rapidly, and there's

1 a different definition of what's rapid for each individual  
2 reservoir, but if you produce more rapidly, you might  
3 create big enough drawdowns that the forces, the pressure  
4 drops within the reservoir might tend to draw the gas be-  
5 fore it's released into the producing well; might not give  
6 it a chance to segregate under the influence of gravity.

7                   You might have more pressure drop and  
8 more gas released, and that would hurt recovery. You could  
9 end up with a lot of your reservoir energy being dissipated  
10 and you would lose the opportunity for this nice, complete  
11 segregation of gas and oil and the possibility of producing  
12 low gas/oil ratio wells for many years.

13                   Mr. Greer has identified this possibi-  
14 lity and has chosen to operate the Canada Ojitos Unit to  
15 take advantage of this method of operation, and I think the  
16 field data shows that he has successfully done that. He's  
17 had low gas/oil ratio wells. They appear to be approached  
18 by a sharp gas/oil contact indicating rather sharp discon-  
19 tinuities between the gas phase and the oil phase that ap-  
20 pears very suddenly and he's taken, you know, he's gotten  
21 the maximum amount of recovery that he could by going so  
22 slow.

23                   Q           Is it possible that this 2-mile wide  
24 area that is in the east -- or west end of the West Puerto  
25 Chiquito but it's not in the pressure maintenance area, and

1 it seems to be an area of contention, is it possible that  
2 that area has some unique qualities that may not be simi-  
3 lar completely to either Gavilan Mancos or West Puerto  
4 Chiquito? I mean you even demonstrated a slightly differ-  
5 ent tank in your presentation.

6 A One of the reasons that I chose it as a  
7 tank was because it is an area of serious contention.

8 Does it have any unique properties?  
9 Well, it's in another permeability plateau. It's -- it's  
10 in a different permeability plateau, let's say, from wells  
11 up structure. It is in communication with areas up struc-  
12 ture but, you know, the characteristics are -- are somewhat  
13 different. The heterogeneity, perhaps, the form of hetero-  
14 geneity begins to vary, but the fact is it is in pressure  
15 communication and in my judgment the whole pool is in pres-  
16 sure communication. It's just that the kinds of permeabi-  
17 lity differences vary. For example, Mr. Powell's maps  
18 showed, I think, simply very high north/south permeability  
19 in the existing pressure maintenance project area, and,  
20 well, that accounts for those contours that it showed.

21 And then when you go into the expansion  
22 area he showed contours of -- of different forms. Well,  
23 that may indicate that within that portion of the reservoir  
24 you may no longer have such very high north/south permeabi-  
25 lity. You may get more north/south variation in pressures.

1           Q           Is it possible that given the fact that  
2 the Proponents and Opponents have very significant exper-  
3 ience with the two separate pools as they exist now, and  
4 some common experience with this area of contention between  
5 the pool boundary and the alleged barrier, that some of  
6 the possibilities that Mr. Hueni has proposed could in fact  
7 be correct about the Gavilan Mancos and perhaps not correct  
8 about West Puerto Chiquito and in transition in the middle?

9           A           It's conceivable. I really don't think  
10 it's likely. I think you're talking about -- particularly  
11 about the matrix containing oil and --

12          Q           And the so-called reverse rate sensitiv-  
13 ity.

14          A           Yeah, I suppose that's conceivable. I  
15 guess my judgment is it's not likely.

16          Q           Well, it's obvious that the opinions are  
17 diametrically opposite. The results of one action in one  
18 case demonstrates or assumes dire results and in the other  
19 assumption it assumes dire results, and it sort of leaves  
20 this Commission with the task of trying to sort out a lot  
21 of professional high quality testimony and no questioning  
22 or impugning people's integrity but with directly diametri-  
23 cally opposite results, one says pressure maintenance  
24 enhances it and one says it ruins it, it leaves us with,  
25 wait a minute, I'm wondering if there isn't a difference

1 from just based on experience with the two people's speci-  
2 fic experience with the pools.

3           A           Well, I don't know, and I, you know, I  
4 certainly appreciate the dilemma that you're in, and I  
5 think the real difference in opinion comes from, you know,  
6 it ultimately comes down to whether or not this is a dual  
7 porosity reservoir, you know, that's what is dominant in  
8 whether or not there should be a gas injection project.  
9 We've had all sorts of testimony about all the bad things  
10 in the Spraberry, and so forth. Well, they're because it  
11 had a matrix that can hinder it.

12                       Now if it were simply fractures with  
13 some significant amount of oil in it, and there were a  
14 place to inject gas at a relatively high structure position  
15 and produce oil low enough that the gas didn't channel  
16 through, then I would think that a gas injection project  
17 would work in Spraberry or anywhere else, in any place that  
18 had a place where you could keep the gas above the oil.  
19 You know, the fundamental consideration is, is it dual por-  
20 osity or not?

21                       So I, you know, I think it's just a dif-  
22 ference in perception, whether that's the case or not.

23           Q           Thank you.

24                       MR. LEMAY: Mr. Brostuen.

25

1 QUESTIONS BY MR.BROSTUEN:

2 Q Dr. Lee, I refer you to your chart on  
3 page 3. I believe you stated that the pressures for the --  
4 or indicated your pressures for the, I assume, your point  
5 at the center COU, I think the number 4 tank, to Mr. Doug-  
6 lass was taken from the rainbow map. It's not a measured  
7 observed pressure, is that correct?

8 A Yes, sir, that's correct. The rainbow  
9 map is an observed pressure.

10 Q Yes, sir, I understand that.

11 A Okay, but yes, it's from the rainbow  
12 map, yes.

13 Q And then Mr. Douglass asked if there was  
14 a pressure for that tank for November of 1977. Is there a  
15 pressure? Was there a pressure taken from a well in that  
16 tank that is not on this chart or was that a mistake?

17 A I don't know. I just don't know. Let  
18 me -- I do think I should tell you what -- what we very  
19 carefully tried to take into consideration in providing  
20 pressures which would find the best possible match.

21 Every pressure which was ordered by the  
22 Oil Conservation Commission was -- was included, no excep-  
23 tions.

24 Secondly, we tried to include pressures  
25 from Mr. Hueni's, I believe it was Exhibit Nine.

1                   We included the earliest pressures in  
2 Gavilan thinking that they would be of significance, and  
3 then simply because of gas we chose three pressures from  
4 the rainbow map. I think those are good quality pressures  
5 but we wanted to minimize the use of those because that's  
6 controversial and to the extent possible we wanted to mini-  
7 mize the controversy about the pressures that we chose to  
8 match.

9                   Q           Which -- which other pressures did you  
10 take from the rainbow map?

11                  A           Well, the highest pressure that you see  
12 on there is 1.

13                  Q           Okay, the X up in --

14                  A           Yeah, the X up near the top.

15                  Q           Okay.

16                  A           The one that I've done a little bit of  
17 struggling with to identify for you, is kind of buried  
18 among a bunch of other pressures. If I can look at my  
19 back-up material here; all right, the pressure in tank num-  
20 ber 3, the West Canada Ojitos Unit expansion area, the  
21 pressure near 1-1-88. It's value is 1015 pounds.

22                  Q           That would be a triangle?

23                  A           Yes, it would be a triangle at 1015  
24 pounds.

25                  Q           Okay. Thank you. You mentioned that it



1 included all the pressures that were required or resulted  
2 from the testing that was required by the Conservation  
3 Commission. Are there other pressures that you're aware of  
4 that are observed pressures that have not been reported to  
5 the Commission or that would support what you have here?  
6 Are there other observed pressures that were taken by  
7 Benson-Montin-Greer or others that you might be aware of?

8 A No, other, you know, other than the  
9 pressures on the rainbow map, surface pressures, which we  
10 don't seem to be able to get quite the credibility for that  
11 we think in general they deserve.

12 There some -- some build-up tests. We  
13 tried to minimize the use of those because of lots of dif-  
14 ferences of opinion on how to extrapolate those, fully  
15 built up, and so forth.

16 So basically our data set out is as I  
17 described to you earlier.

18 Q Okay, thank you. On your page 26, the  
19 Horner semilog analysis, and I believe in the testimony you  
20 expressed the hump (not clearly understood) the Horner  
21 time, approximately?

22 A Yes, sir.

23 Q (Not clearly understood).

24 A Not just that hump, the whole shape of  
25 the curve.

1 Q The whole shape of the curve?

2 A You can have -- phase redistribution can  
3 cause a curve shape, let's say that hump weren't there, to  
4 just come up sharply, level out, and then come back up  
5 again without any hump. That can be due totally to phase  
6 segregation in all these reservoirs, and that's really the  
7 interpretation that Mr. Weiss gave this, you know, I'm  
8 sure he said that that period, that little hump is just bad  
9 data and basically honored the other data.

10 Q Okay. Phase segregation is affected by,  
11 and the affect of phase segregation upon a Horner analysis  
12 is affected significantly by gas/oil ratio and the produc-  
13 tion, isn't that correct?

14 A Generally you need significant amounts  
15 of oil and gas --

16 Q That's correct.

17 A -- in the wellbore.

18 Q That's right, so the higher the percent-  
19 age of oil, the greater the effect on the (unclear) distri-  
20 bution?

21 A No, you need quite a bit of gas. In  
22 other words, if you have very little gas --

23 Q Certainly, certainly, you have to have,  
24 but do you know whether -- what the gas/oil ratio and pro-  
25 duction rate was just prior to shutting in this well for --

1           A           Yes.   Excuse me, gas/oil ratio for both  
2 these two wells that we show here is in the range of  
3 3-to-4,000 standard cubic feet per stock tank barrel. The  
4 production rate prior to shut-in, I can get that number for  
5 you if you could give me just a second.

6           Q           Okay, I wish you would, please.

7           A           On the Mobil Lindrith Well the rate just  
8 prior to shut-in was 221 barrels of oil per day; gas/oil  
9 ratio was 4023 cubic feet per barrel.

10                   On the High Adventure the rate just  
11 prior to shut-in was 162 barrels per day; the gas/oil ratio  
12 was 3605 cubic feet per barrel.

13           Q           Do you consider the volume of oil being  
14 produced just prior to shut-in and the volumes of gas being  
15 produced to be sufficient, the phase redistribution result-  
16 ing from that in the wellbore would be sufficient to cause  
17 the effect -- or result in the interpretation you have that  
18 what we're seeing is phase redistribution and not dual por-  
19 osity?

20           A           Yes.   Well, you know, I don't think  
21 there's much question about it in the case of the Sun High  
22 Adventure.

23                   The only other major possibility I can  
24 think is a leak.   You know, that happens, but that leak  
25 seems to have healed itself because the pressure then later

1 built back up.

2           Q           The reason why I introduced that second  
3 well, which is clearly phase segregation, is to show that  
4 the characteristics of this formation or the producing, the  
5 well operations, the way wells are produced and the gas/oil  
6 ratios if they go any higher, this is a combination of  
7 circumstances in which phase redistribution appears with  
8 some frequency in well tests. In some cases it's very  
9 clear. Now when it's very clear, that means that there's a  
10 possibility that it will affect tests in more subtle ways,  
11 like maybe giving a shape that looks like dual porosity  
12 reservoir.

13                   I think in the case of the Lindrith,  
14 though, we still do have a little hump, which makes the  
15 case even stronger. But, see, what we're trying to look  
16 for is a consistent pattern. We really don't see a consis-  
17 tent pattern, a curve shape, which I think can reasonably  
18 be interpreted as a dual porosity reservoir, and that would  
19 be evidence that I would like to have before I would con-  
20 clude that it's a dual porosity reservoir.

21                   I worked a lot in dual porosity reser-  
22 voirs. Currently I'm working in a major research effort  
23 for the Gas Research Institute, looking at the eastern  
24 Devonian shales, which is very clearly a dual porosity re-  
25 servoir.

1 By and large the build-up tests there  
2 have that shape, you know, you test one, you see that  
3 shape; you test another, you see that shape. It's very  
4 characteristic. We just don't see that pattern here, but  
5 we do see some semblance of a pattern of phase redistribu-  
6 tion. It's because we see it with some frequency I saw I  
7 would conclude that as a probability, not certainty, but a  
8 probability, that that phase redistribution is the cause of  
9 the shape in wells such as the Mobil Lindrith B-37.

10 Q Thank you, very much. That's all.

11

12 QUESTIONS BY MR. LEMAY:

13 Q Dr. Lee, back again to your page 3, I'm  
14 trying to focus on injected gas, how much there was and  
15 where did it go, I guess.

16 The excess injected over production oc-  
17 curred between you say 1973 and '77, or what years are we  
18 over-injecting?

19 A It's going to be based, you know, I  
20 can't tell you exactly. We can look at the production sta-  
21 tistics if you want, but I think generally whenever the  
22 pressure is going up in a reservoir as a whole we're over-  
23 injecting. Well, the pressure in the reservoir as a whole  
24 starts going up about 1973.

25 Q Okay, that's assuming where you don't

1 have pressure points that your analysis is correct.

2 I'm trying to get back to the assump-  
3 tions where you have a system where you put in gas and you  
4 take out gas and oil, I'm assuming there's a net balance  
5 there of more gas being injected than is being expelled.

6 A Yeah, right.

7 Q No release points.

8 A Yeah, and you know, that's not an as-  
9 sumption, and I don't -- I don't think that that's a point  
10 of controversy here. The -- our opposition may think that  
11 there's another explanation for why over-injection didn't  
12 result in effects that they're looking for but there's no  
13 question but what during this time period from about '73,  
14 to probably '84 or '85, there's no question but what there  
15 was more injection than there was production. We have the  
16 injection/production statistics to look at and if we can  
17 see that we injected more that we produced, then by defini-  
18 tion that's over-injection.

19 Q Right. Do you know how much gas net in  
20 that period of time has been over-injected?

21 A I -- I can get those statistics for you.  
22 I don't have them at my fingertip and it may take some  
23 work. Would you like for me to provide those to you at my  
24 earliest convenience?

25 Q I think it might help, only to the point

1 we're trying to talk about degree and also if there are  
2 some statistics as to when that over-injection by year  
3 occurred, so there's a possibility it will match in with  
4 pressure.

5 Mr. Kellahin.

6 MR. KELLAHIN: Mr. Chairman,  
7 we would hope to provide that to you during the period  
8 which the Commission will call back witnesses for addition-  
9 al questions.

10 MR. LEMAY: That would be  
11 helpful.

12 MR. KELLAHIN: And if that  
13 might be a time for Dr. Lee to provide that answer we'd  
14 appreciate that opportunity.

15 MR. LEMAY: We'd so much ap-  
16 preciate that. It is an issue we're trying to focus on.  
17 Thank you.

18 Q One other point with your broad range of  
19 experience, you mentioned Devonian shale dual porosity, and  
20 focusing on that issue, are you familiar with any reservoir  
21 with a single fracture porosity system, no matrix, that has  
22 been quote successfully waterflooded for pressure mainte-  
23 nance?

24 A I think we have a perfect example right  
25 here and this is the Canada Ojitos Unit, the West Puerto

1 Chiquito. I think that project is succeeding admirably,  
2 and if you want a rock that's just like the rock we're  
3 considering in Gavilan, or at least pretty close to it,  
4 you know, you just can't find a better analogue.

5 Q That might be debated by the other side,  
6 whether that was successful or not. Maybe that's a good  
7 point to debate, but I'm looking beyond this particular  
8 example, of any -- any other fractured shale, highly frac-  
9 tured limestone, anything without a dual porosity system,  
10 where there's been a successful pressure maintenance pro-  
11 ject that you know of.

12 A No, I don't have a list of either suc-  
13 cesses or failures. I would have to go through the litera-  
14 ture and talk with (unclear). I cannot provide you either  
15 successes or failures.

16 Q Well, where it's been tried, are you  
17 familiar with any situations where it's been tried?

18 A Well, what I'm not sure of is whether  
19 there was, you know, whether there was matrix, and that's  
20 why I would have to give that considerable thought.

21 Q I didn't want to put you on the spot but  
22 I thought it would help us with reference if we could get  
23 another example.

24 MR. LEMAY: I have no further  
25 questions. Is there anything additional? Yes, sir, Mr.



1 Kellahin.

2 MR. KELLAHIN: Mr. Chairman, I  
3 would prefer to go last in discussing questions with Dr.  
4 Lee and Mr. Douglass has said that Mr. Humphries' question  
5 has prompted some additional questions for Mr. Douglass,  
6 and it would be my preference to have him complete his  
7 examination before I talk to Dr. Lee.

8 MR. DOUGLASS: Thank you.

9 MR. LEMAY: Fine. Mr. Doug-  
10 lass.

11

12 RECROSS EXAMINATION

13 BY MR. DOUGLASS:

14 Q Dr. Lee, let me ask you with reference  
15 to what would be a logical explanation for what we see out  
16 here in this area.

17 First of all, I understand you don't  
18 think the barrier is there.

19 Assume with me at least in this series  
20 of questions that there is a barrier there. Would you  
21 agree that east of the barrier we have a very steeply dip-  
22 ping, fractured reservoir, according to your examination  
23 or understanding of the area?

24 A Yes, sir.

25 Q Have you made any calculations in that

1 are how effective gravity drainage would be as a drive  
2 mechanism east of the barrier as we say, or where it appro-  
3 ximately exists on the map that we presented?

4 A Yes. I presented testimony to that  
5 fact.

6 Q Would it be an effective drive mechan-  
7 ism?

8 A In my judgment, yes, it would.

9 Q And if you added gas to that it would  
10 assist the gravity drainage provided you didn't put in  
11 enough gas where it bypassed the oil and went to the wells,  
12 is that correct?

13 A Yes,

14 Q As I recall, the area east of the bar-  
15 rier as we show it, has been produced roughly up to an  
16 average of about 1000 barrels a day over its life, would  
17 that be about --

18 A I'll take your word for it. I'm not  
19 sure. I only know current rate but that's probably about  
20 right.

21 Q I think we did some figures on another  
22 exhibit that showed what its average has been, 312,000, or  
23 something like that. It was even a little less than 1000  
24 barrels a day.

25 Now, one of the problems that you would

1 have with that type of thing is that that you think there  
2 has been over-injection in that area, so where did the gas  
3 go, is that right?

4 If there was a barrier here, then that  
5 gas had to go somewhere.

6 A If there were a barrier there I would  
7 think the pressure would have gone out of sight.

8 Q Is there a possibility then that this  
9 gas has been leaking off somewhere up structure in this --

10 A Mr. Greer has worried about that possi-  
11 bility, not because of, you know, any indication it was,  
12 but since he began to inject gas, he's worried about the  
13 surface and he had looked hard for that.

14 Q The -- one of the exhibits we put up  
15 here showed that this Boulder Field, which I understand is  
16 just north of here in the Mancos formation had recovered on  
17 the average of about 900 barrels per acre. That would be  
18 an extremely high recovery down here in the area that we're  
19 talking about, wouldn't it?

20 A Yes.

21 Q Do you know if any investigation has  
22 been made to see if that might be the source for where this  
23 over-injected gas went during this period of time?

24 A Oh, I don't know of any investigation,  
25 but I know there's a pretty strong feeling that there is

1 very poor communication between this area and some of the  
2 areas to the north.

3 Q Well, it wouldn't take much communica-  
4 tion for gas to move through the formation, though, would  
5 it?

6 A It -- it would take permeability over a  
7 very considerable -- over a very considerable area, con-  
8 tinuous permeability, and with -- well, I'll stop there.

9 Q The -- and, of course, if you were  
10 causing a greater pressure differential, that is, if you  
11 were producing those wells up there in Boulder, causing a  
12 larger pressure differential than Mr. Greer was producing  
13 his wells even closer to the injection source, the gas  
14 might still move and probably would move to the area of  
15 lower pressure, wouldn't it?

16 A Given permeability, gas would move from  
17 high pressure to low pressure.

18 Q That is one object that or one physical  
19 law I think we're all in agreement on, is that fluid moves  
20 from high pressure to low pressure.

21 A Yes, sir.

22 Q Now let's -- let's go over in the area,  
23 assuming the barrier is there, and we have this Gavilan and  
24 expansion area. Let's assume that is one common reservoir.  
25 I believe we visited in March of '88 that although you

1 hadn't done any specific calculations you were satisfied  
2 that if you were going to use gravity segregation as a  
3 producing mechanism in that area because of the low relief  
4 that the rates from the well would probably be below the  
5 economic limit. Is that a fair summary of our visit last  
6 time?

7 A The rates would be -- would be much  
8 lower than in the Canada Ojitos Unit. Just how low, I  
9 don't know about that.

10 Q If the barrier exists and if there is a  
11 separate reservoir that consists of the Gavilan and the  
12 pressure maintenance expansion area, in your opinion would  
13 that area, if it were separate from the injection project,  
14 would it operate under a solution gas drive mechanism?

15 A Yes.

16 Q Under a solution gas drive mechanism if  
17 you increase the rate of oil production should the gas/oil  
18 ratio go down if you lower the bubble point?

19 A No.

20 Q If you're in a solution gas drive reser-  
21 voir and you lower the bubble point and the oil rate goes  
22 up and the producing ratio goes down, doesn't that indicate  
23 to you contribution by the matrix to the oil production?

24 A Not necessarily. There is an alterna-  
25 tive explanation. You know, it could be simply the way of

1 producing the well.

2 Q But it also just as reasonably could be  
3 a matrix contribution.

4 A That's a possibility. I think we need  
5 to look for a possibility that's consistent with all the  
6 facts that we see, and then we have some suggestions for  
7 other possibilities.

8 Q But it would be a reasonable explana-  
9 tion.

10 A It would be a reasonable explanation if  
11 we could verify by finding a matrix with permeability, yes,  
12 sir.

13 Q Now, I think Mr. Humphries had probably  
14 the same problem I do in understanding, is that we've got a  
15 matrix that has a large amount of oil and it's connected by  
16 a fracture system and we've created a pressure differential  
17 where the oil goes into the fracture system.

18 Why, at some point in time can't I put  
19 gas back in that reservoir and start pushing that oil out  
20 of that matrix?

21 A Well, the matrix prefers to have oil in  
22 it relative to gas. It's like a sponge, it would rather  
23 have water than air.

24 You can push the water out of a sponge  
25 but you, you know, you've got to push it out with air under

1 pressure.

2 Q Well, although I know you don't agree  
3 with what's the concept that the Proponents have with the  
4 reservoir, if they're concept of the reservoir is correct,  
5 then gas injection is not going to help recover any addi-  
6 tional oil out of the Gavilan and the pressure maintenance  
7 expansion area, is it?

8 A That's correct.

9 MR. DOUGLASS: Pass the wit-  
10 ness.

11 MR. LEMAY: Additional ques-  
12 tions? Yes, sir, Mr. Pearce.

13 MR. PEARCE: Real quickly, Mr.  
14 Chairman.

15

16 CROSS EXAMINATION

17 BY MR. PEARCE:

18 Q Dr. Lee, I notice in the righthand side  
19 of the map, base map, there is a niche in the Canada Ojitos  
20 Unit which has some wells in it. Do you know anything  
21 about those wells?

22 A No, sir, I don't.

23 Q You don't know if they were initially  
24 unit wells?

25 A No, I don't.

1           Q           You mentioned earlier that you and Mr.  
2 Hueni in your opinion agreed relatively closely on the  
3 possible recovery, and your example was his low pressure  
4 gas injection scenario presented at a previous hearing, is  
5 that right?

6           A           That's correct.

7           Q           And you remember that he did not agree  
8 that high pressure gas injection would be beneficial at  
9 all?

10          A           That's correct.

11          Q           And were you in the room when he has  
12 discussed at this hearing that in view of the effects of  
13 imbibition he now believes that no gas injection would be  
14 effective in this reservoir.

15          A           That's correct about that. I was using  
16 his example simply to serve as a qualitative check on the  
17 magnitude of the answer. Of course, his previous calcula-  
18 tion did not include capillary effects and therefore he  
19 would not have seen any effect of imbibition and therefore,  
20 even though it was a dual porosity reservoir, in a lot of  
21 ways it was operating like a solution gas drive reservoir,  
22 the same model that I have, and therefore it's a check if  
23 we get roughly the same answer with a pressure injection  
24 project.

25                       We did. I think it confirms that my



1 simplified calculation (not clearly understood) correct.

2 Q All right, Dr. Lee, looking at page 2 of  
3 your Exhibit Number One, the exhibit in which you set out  
4 the cells or tanks using your analysis, I notice that you  
5 show 3 darcy feet, I assume that's transmissibility,  
6 between tanks, what we are now calling 3 and 4, the expan-  
7 sion area and the central Canada Ojitos Unit, as you refer  
8 to it.

9 A Yes.

10 Q Can you explain the lack of response  
11 after the C-34 well was fraced, lack of response in the  
12 B-29 and B-32 if there is 3 darcy foot transmissibility?

13 A I disagree totally with that interpreta-  
14 tion of the interference test. There was clearly response  
15 of exactly the size you would expect with the kind of per-  
16 meability (unclear).

17 Q Thank you. Nothing further, Mr. Chair-  
18 man.

19 MR. LEMAY: Additional ques-  
20 tions? If not, Mr. Kellahin.

21 MR. KELLAHIN: Thank you.

22 MR. LEMAY: You may proceed.

23

24

25

## 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.

1 He has taken those same two bits of information about the  
2 unit, plotted those, made the calculation, he will also  
3 show a rate of decline in the unit of about 11 pounds a  
4 year, will he not?

5 A Yes, sir.

6 Q If you'll turn to Exhibit Number One to  
7 your display on page 3, in using your material balance  
8 verifications, you have told us as a result of gas over-  
9 injection in the unit we can have a pressure curve for the  
10 unit that honors the data point in the C-34 Well both in  
11 1971, as well as in 1987, and have a hump in the curve.

12 A Yes, sir, I tried to state that earlier  
13 in response to a question, but again, yes, with the path in  
14 between it could be anything and therefore let's develop a  
15 model of the reservoir which seems to explain what's going  
16 on and we'll see what that path is likely to be, but it  
17 certainly could go up in between.

18 Q So Mr. Roe and Mr. Hueni can say that we  
19 have pressure decline in the unit of 11 pounds a year  
20 using those as the data points and not be inconsistent with  
21 the conclusions and analyses that you've made.

22 A Yes, in fact, the context of the tran-  
23 script that I saw sort of indicated that that was the kind  
24 of calculation that was made.

25 Q Let's assume that intermediate period

1 ends in 1986, somewhere about then, I'll ask you to pick  
2 the point, but when we look on page 3 can we take that  
3 intermediate point and simply disregard it, examine the  
4 later time on your display on page 3 and draw any conclu-  
5 sions about the presence or absence of the barrier?

6 A I think we have to take everything into  
7 account. What has happened historically, you know, that  
8 would be part of our observation points today.

9 Q Can we ignore the early time, the inter-  
10 mediate time, and take the last portion of the display for  
11 the last couple of years and draw any conclusions about  
12 that with regards to the barrier?

13 A Oh, I'm sorry. With all the pressures  
14 declining, despite a lot of injection, I think that indi-  
15 cates that there is significant pressure communication with  
16 all the pressure declining in step. To me that would again  
17 indicate lack of a barrier.

18 Q So we can just ignore all the rest of  
19 this until we get to the last 20 percent of the display and  
20 you can still analyze it and show that there is no barrier.

21 A I think so. In fact, as we did earlier  
22 today, you can take a 6-month period (unclear) the barrier.

23 Q Let's talk about the sponge and how we  
24 can squeeze that sponge.

25 If you'll turn to page 17 of your

1 report, Exhibit Number One, Commissioner Humphries says it  
2 was hard for him to disregard Mr. Hueni when Mr. Hueni says  
3 we need to get a large pressure differential in order to  
4 get that matrix to produce.

5 Can we take that 6-section area on the  
6 Proponents Exhibit Number Five, we have -- we have a 6-sec-  
7 tion area that's the sponge, do we not?

8 A Yes.

9 Q And the field observations in that  
10 6-section area contain 8 wells.

11 A Contains more than 8 wells here, I  
12 think.

13 Q Let's assume that we look at 8 wells --

14 A All right.

15 Q -- within the 6-section area. From ini-  
16 tial reservoir pressure down to present times we have  
17 squeezed that sponge by 1000 pounds, have we not?

18 A We've provided a 1000 pound driving  
19 force to get the oil out of the matrix, to squeeze the  
20 sponge.

21 Q And what is happening with those 8 best  
22 wells within that area?

23 A Well, they're not the best wells in the  
24 area. They were 8 wells that were formerly quite good  
25 wells on the average and what's happening to them is that

1 they're dying.

2 Q We can't squeeze that sponge hard enough  
3 with 1000 pounds below initial reservoir conditions to get  
4 the oil out of the matrix if it was ever there.

5 A It sure doesn't appear to be coming.

6 Q Is there any other way to take a field  
7 observation test and show that you can't squeeze the sponge  
8 any harder?

9 A I think that's the most direct evidence  
10 probably possible. The rest is based a lot on interpreta-  
11 tion but this is pretty direct.

12 Q Okay. Taking those rates up to the high  
13 allowable and squeezing the sponge at the high rates is not  
14 going to get us oil out of there, is it?

15 A Right.

16 Q But your fundamental point is the oil is  
17 not there anyway.

18 A Right, that's my point.

19 Q Thank you.

20 MR. LEMAY: Thank you, Mr.  
21 Kellahin.

22 Other than starting another  
23 witness I --

24 MR. DOUGLASS: Mr. Chairman.

25 MR. LEMAY: Yes, sir.

1 MR. DOUGLASS: I have some  
2 additional questions, if I may.

3 MR. LEMAY: Fine, excuse me.  
4

5 RECROSS EXAMINATION

6 BY MR. DOUGLASS:

7 Q Dr. Lee, Mr. Kellahin asked you if Mr.  
8 Roe had taken that pressure in the C-34 and then calculat-  
9 ed it from the original pressure he'd gotten about this 11-  
10 pound pressure drop. Do you recall that?

11 A Yes, sir.

12 Q All right, sir, are you aware that the  
13 pressure measurement in the C-34 was made in November of  
14 1987?

15 A I'm really just not familiar with it.

16 Q Well, assume with me that it was made in  
17 November of 1987. In fact, I believe you can look at Mr.  
18 -- Mr. Hueni's Exhibit Twenty and see that the pressure is  
19 shown right at the -- essentially at the end of the year,  
20 isn't it?

21 A Yes, sir.

22 Q And I assume you're aware that Mr. Roe  
23 testified in March of 1987 about the pressure decline.

24 A I don't remember that testimony.

25 Q Our Exhibit Fifty-one?

1 A Oh.

2 Q So there wouldn't have been any way that  
3 he could have taken the C-34 pressure in November of '87  
4 and calculated an 11 pound pressure drop and testified  
5 about it in March of '87, could he?

6 A Couldn't have been based on that parti-  
7 cular pressure measurement.

8 Q Let's look at the 8 wells that you're  
9 talking about there with Mr. Kellahin. Did you have a  
10 graph of their production and gas/oil ratio on page 19?

11 A Yes, sir.

12 Q After June of -- well, let me ask you,  
13 is the -- is January of 8 -- is June of '87 or July of '87  
14 right over the 1987 there, in other words the year period  
15 goes to your slashes to slashes, is that correct?

16 A Yes, sir, that's correct.

17 Q Does it appear that each time the oil  
18 production rate leveled out or went up that the gas/oil  
19 ratio went down with reference to those 8 wells?

20 A That's true on a short term basis, but  
21 we still got the obvious trend.

22 Q It's true on a short term basis with  
23 reference to four separate events on your chart here.

24 A Yes, sir.

25 Q The reasonable explanation of that could



1 be oil coming through the matrix, is that right?

2 A That is one explanation. We believe we  
3 have others.

4 Q And let me ask you about -- don't you  
5 show that the total daily oil production from those 8 wells  
6 as you describe them, about to die, is about 60 percent or  
7 in excess of 60 percent of the total production coming from  
8 the pressure maintenance area currently?

9 A But the pressure -- well, the answer is  
10 yes.

11 MR. DOUGLASS: Pass the wit-  
12 ness.

13 MR. LEMAY: Additional ques-  
14 tions? Mr. Kellahin.

15

16 REDIRECT EXAMINATION

17 BY MR. KELLAHIN:

18 Q Your explanation to the last question?

19 A Well, the -- in the case of the pressure  
20 maintenance area, of course, the -- we have gravity drain-  
21 age of oil down to wells in the expansion area. I think  
22 the evidence is very clear, there seems very clear pres-  
23 sure support. Those wells are not about to die. We've --  
24 we've moved past some of the wells in the current pressure  
25 maintenance area where the gas/oil contact was clearly

1 gravity drainage and continuing movement of oil down  
2 structure.

3 MR. KELLAHIN: Nothing fur-  
4 ther.

5  
6 QUESTIONS BY MR. LEMAY:

7 Q I have a question, Dr. Lee.

8 A Yes.

9 Q In analyzing on page 19, just a straight  
10 production plot in a fractured reservoir, with matrix con-  
11 tribution, is it common to see that curve at a point in  
12 time where the fracture system is depleted to turn on a  
13 different angle? In other words, have a bend in that where  
14 the matrix starts contributing? Is there a characteristic  
15 curve to a dual porosity system well?

16 A Characteristic curve but it occurs in  
17 heterogeneous reservoirs; occurs in layered reservoirs, for  
18 example, where we've got -- we deplete one layer of higher  
19 permeability and there's another lower permeability layer,  
20 and it's harder for that oil or gas to come out but, you  
21 know, it comes once there's a big enough pressure differ-  
22 ence from the other layer. It's generally characteristic  
23 of heterogeneous systems, one of which is a dual porosity  
24 system.

25 Q But as far as a fingerprint for a dual

1 porosity system decline curve or a single porosity, frac-  
2 ture only system, there is not any differentiation in the  
3 production versus time plot?

4 A I don't know. I know there are a lot  
5 of, you know, certainly not this leveling out. That's  
6 pretty characteristic of just an awful lot of formations  
7 all over the world. They will decline, say, exponentially  
8 for awhile but not forever. They will eventually level out  
9 due to the lower permeability parts of the system whether  
10 it be layers or a matrix in a dual porosity system, or just  
11 generally lower permeability rock; more common than not.

12 MR. LEMAY: Additional ques-  
13 tions?

14 If not, the witness may be ex-  
15 cused.

16 Thank you, Dr. Lee.

17 Rather than start another wit-  
18 ness I think it's best we adjourn and we'll reconvene to-  
19 morrow morning at 8:30.

20

21 (Hearing adjourned.)

22

23

24

25

## 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