

1 STATE OF NEW MEXICO
2 ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
3 OIL CONSERVATION COMMISSION
4 STATE LAND OFFICE BUILDING
5 SANTA FE, NEW MEXICO

6 16 June 1988

7 COMMISSION HEARING

8 VOLUME IV OF V VOLUMES

9 IN THE MATTER OF;

10 A hearing in the matters involved CASES
11 in Cases Nos. 7980, 8946, 8950, 7980, 8946,
12 9111 and 9412. 8950, 9111,
13 9412.

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

17 TRANSCRIPT OF HEARING

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24
25

A P P E A R A N C E S

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(Hereafter at 8:30 o'clock a. m. on the 16th

3

day of June 1988 the hearing was reconvened

4

and the following proceedings were had, to-

5

wit:)

6

7

MR. LEMAY: The hearing will

8

come to order. Let's get this show on the road.

9

Mr. Kellahin.

10

MR. KELLAHIN: Thank you, Mr.

11

Chairman. We'd like to call as our next witness, Mr. John

12

Roe.

13

Mr. Roe's exhibits were circu-

14

lated on Monday. They are the exhibits in the legal size

15

manila folder.

16

17

JOHN D. ROE,

18

being called as a witness and being duly sworn upon his

19

oath, testified as follows, to-wit:

20

21

DIRECT EXAMINATION

22

BY MR. KELLAHIN:

23

Q

Mr. Roe, for the record would you please

24

state your name and occupation?

25

A

My name is John Dale Roe, Junior, and

1 I'm a petroleum engineer for Dugan Production.

2 Q Mr. Roe, are you a Registered Profes-
3 sional Engineer?

4 A Yes, sir.

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

7 A Yes, I have.

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

13 A Yes, I have.

14 Q And were you an expert witness in the
15 Commission hearings in November of 1983 to consider the es-
16 tablishment of temporary rules for that pool?

17 A Yes, I was.

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

20 A Yes.

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

24 A Yes.

25 Q Have you testified concerning the

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

3 A Yes, sir.

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

7 A Yes, I did.

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

11 A Yes, I have.

12 Q And have you analyzed that data?

13 A Yes.

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

16 MR. LEMAY: His qualifications
17 are acceptable.

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

23 A Yes, I am.

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

1 A Yes, I have.

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

5 A Would you repeat your question, please?

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

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

12 Q What were the temporary producing and
13 gas/oil ratios established by that hearing in November of
14 1983?

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

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

24 A Yes, I do.

25 Q And what is that opinion?

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

4 Q In dealing with your study and involve-
5 ment of the Gavilan Mancos production, as well as the pro-
6 duction from the West Puerto Chiquito Mancos, have you seen
7 operationally whether or not you can separate the two pools
8 using the current boundary between pools based upon the
9 production being in either the A, B, C zone or some combin-
10 ation?

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

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

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

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

23 Q What, to your knowledge, has occurred
24 along the current boundary between the two pools that would
25 give you a basis of support for allowing that boundary to

1 remain where it is?

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

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

25 A That would be kind of a reddish brown

1 colored bound set of statistical information.

2 Q Would you identify for us what is con-
3 tained in that bound volume, Mr. Roe?

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

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

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

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

17 Q The production statistics for the Gavi-
18 lan Mancos Pool will include the high and low rate test
19 periods?

20 A Yes, that is correct.

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

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

25 Q Mr. Roe, let me direct your attention

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

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

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

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

11 In the green pages we pretty much pre-
12 sent the pool total production.

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

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

20 The one thing that might be particularly
21 useful is that Mr. Greer has a practice of referring to
22 wells by their unit letter and section; in other words,
23 A-20 is a well that he commonly refers to; however, the
24 Commission records would reflect that that's Unit Well No.
25 36, and so the gold page in this book has a cross reference

1 between unit well number and unit letter section -- it
2 actually identifies the location of the well.

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

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

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

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

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

16 A Yes, it does.

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

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

22 Q Mr. Roe, one of the issues the Commis-
23 sion asked that it be studied and addressed was Issue Num-
24 ber 3 on the docket sheet when it talks about an analysis
25 and interpretation of the results of the June 27th, '87, to

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

3 Have you reviewed that information and
4 have you made an analysis and interpretation of those re-
5 sults?

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

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

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

16 The initial production phase began July
17 1st of 1987 and ended on November 16th of 1987.

18 Q How many days did that test cover?

19 A It covered 138-day period or approxi-
20 mately 4-1/2 months.

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

23 A The total gas produced during that per-
24 iod was 2. -- nearly 2.2 billion cubic feet.

25 Q And what was the total oil produced?

1 A 443,200 barrels of oil.

2 Q And what did you observe in terms of
3 pounds of pressure loss per month during the test period?

4 A Okay. During this 4-1/2 month test
5 period we averaged approximately 203 pounds -- or the aver-
6 age pressure loss throughout the duration of the test was
7 203 pounds.

8 Q And on a monthly average, what is that,
9 sir?

10 A That relates to approximately 45 pounds
11 a month, given that we were covering a 4-1/2 month period.

12 Q In analyzing the data with regards to
13 those numbers, did you include within those production num-
14 bers wells other than the Gavilan Mancos Pool wells?

15 A No, that pretty much just reflects the
16 production within the Gavilan Mancos Pool.

17 Q And when we talk about the Gavilan Man-
18 cos Pool, we are talking about that area exclusive of the
19 expansion area which lies in the West Puerto Chiquito
20 Mancos Pool.

21 A Yes. We -- all references that we will
22 make to the Gavilan Mancos are pretty much as the Commis-
23 sion records reflect the Gavilan Mancos Pool to be.

24 Q At such instances that you deviate from
25 that basis you will let us know that you've included some-

1 thing else?

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

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

7 A During the period July through mid-
8 November, a 320-acre spacing unit was permitted to produce
9 640 barrels of oil per day and 1280 MCF of gas per day.

10 Q Is there a corresponding statewide al-
11 lowable for a depth bracket for wells at this depth that
12 use either a 320-acre or 640-acre spacing?

13 A There is not.

14 Q And what specific rule are you referring
15 to?

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

18 Q And stops at 160-acre spacing?

19 A That's correct.

20 Q When we look at the low rates test peri-
21 od, Mr. Roe, what are the dates for the low rate test peri-
22 od?

23 A The lower rate of production that was
24 the second production phase of the test period was at the
25 current pool allowable rate and that was a period that the

1 production began on November 20th and ended on February
2 20th of 1988, November 20th being in 1987.

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

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

7 Q And what was the total gas produced dur-
8 ing the test?

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

11 Q And what is the total oil produced dur-
12 ing the test?

13 A 143,400 barrels of oil.

14 Q And what was the total psi drop during
15 the test on an average basis for the Gavilan Mancos reser-
16 voir?

17 A The -- 23 pounds for the total period.

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

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

23 Q When we look at the results from the ob-
24 served data in the high rate test period, Mr. Roe, did you
25 find any of the Gavilan Mancos Pool wells that could pro

1 duce at the top oil allowable?

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

6 Q For the oil?

7 A Right.

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

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

14 Q When we talk about producing at various
15 gas/oil ratio limitations throughout the life of this re-
16 servoir, if we establish that gas/oil ratio at 2000-to-1,
17 and make that effective after this hearing, are you satis-
18 fied that that can remain a permanent solution for this
19 reservoir?

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

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

1 Commission in May of this year?

2 A Yes, I have.

3 Q And have you had an opportunity to re-
4 view his final report submitted in the hearing earlier on
5 Monday of this week?

6 A Yes.

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

9 A Yes, I was.

10 Q Let me direct your attention, Mr Roe,
11 to that portion of Mr. Weiss' report which is found on page
12 8 of his report.

13 If I might approach the witness, Mr.
14 Chairman?

15 MR. LEMAY: Fine.

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

19 A Yes, he has.

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

22 A There are only 74 wells that are comple-
23 ted and available for production in the Gavilan Mancos
24 Pool, so I'm sure that he did include some wells from the
25 West Puerto Chiquito Pool.

1 Q If we look on the 74 wells in the Gavi-
2 lan Mancos Pool, Mr. Roe, would you refresh our recollec-
3 tion and describe as concisely as you can the method by
4 which Mr. Weiss analyzed the results to get to his 46 wells
5 that he's shown us in that paragraph on page 8?

6 A Okay. Well, Mr. Weiss was presented
7 with the same information that each of the operating opera-
8 tors within the pool were presented with, which was a tre-
9 mendous amount of production in terms of barrels per month
10 or actually barrels of oil per day, and the gas production
11 such that he could compute the gas/oil ratio and the daily
12 average, or use the daily average that was provided.

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

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

19 A Well, I -- I agree that what Mr. Weiss
20 did is generally a good method to analyze the rate sensiti-
21 vity if you are in fact plotting data that varies at ran-
22 dom. The fact that the data generally plotted is reflecting
23 pretty much the maximum capability of the wells throughout
24 the total test.

25 Q Did all 46 wells that Mr. Weiss tabu-

1 lated reflect the ability to be influenced by capacity
2 rather than rate -- rather than the allowable?

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

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

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

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

13 A Of the 74 wells that are completed for
14 production, there's 31 of them that are limited by the
15 current pool allowable of 400 barrels of oil per day and
16 240 MCF per day for a 320-acre spacing unit.

17 My exhibit when we get to it will re-
18 flect that there are no wells that are limited by the al-
19 lowable that existed during the initial production phase of
20 the test period.

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

24 A Yes, I have.

25 Q And how many do you tabulate?

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

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

10 A Yes, I have.

11 Q And how many wells do you get?

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

16 Q We've had some questions earlier this
17 week with regards to the 72-hour pressure build-up. Do you
18 have an opinion concerning whether the 72-hour pressure
19 build-up, do you have an opinion concerning whether the
20 72-hour build-up before the test was adequate?

21 A Yes, I have.

22 Q And what is that opinion?

23 A I believe that the 72-hour, it was not a
24 randomly picked test. Mr. Chavez called all of the opera-
25 tors together. We agreed upon the test procedure based

1 upon the pressure data we had to start with, and we mutu-
2 ally agreed that the 72 hours would be adequate and it was
3 especially important to -- that all operators use the same
4 procedures so that in the event there was some degree of
5 unstabilization, although we didn't feel that would be a
6 significant problem, but we would at least be comparing a
7 72-hour pressure in each well at different planes of pres-
8 sure depletion in the reservoir.

9 Q Is that more important to you as an en-
10 gineer in setting up a test than having wholly stabilized
11 wells before the production test period?

12 A Well, it is to me, from the standpoint
13 that quite a few of the wells in the Gavilan are equipped
14 with artificial lift equipment such that obtaining a pres-
15 sure build-up is possible only by either using fluid levels
16 or removing the production equipment from the well. Once
17 you've removed the production equipment from the well, then
18 you've got to use some other method to get the well to pro-
19 duce at a somewhat stabilized rate before you start your
20 build-up and requiring a fairly large expenditure on the
21 part of any one operator, and so the Commission did not
22 think that it was a justifiable expense to require each op-
23 erator that was equipped with artificial lift equipment to
24 gather production data from a pressure build-up and from
25 the standpoint that we felt each operator would be obtain-

1 ing a 72-hour pressure, if the engineers that agreed upon
2 that test procedure felt that we would be adequate with 72
3 hours.

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

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

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

20 A During the second phase of the produc-
21 tion test, which was the lower rate, we actually averaged
22 approximately 6200 barrels of oil per pound of pressure
23 loss within the Gavilan Mancos Pool.

24 Q When you analyze the results from the
25 high rate test period in terms of barrels of oil produced

1 per pound of pressure loss during that test period, what
2 did you find?

3 A It averaged about a third of what we did
4 during the second phase. The actual number was 2200 bar-
5 rels of oil per psi loss.

6 Q Do you attach as an engineer any signi-
7 ficance to that?

8 A Yes, sir, I do.

9 Q And what is that?

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

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

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

23 A Well, the basic conclusion is that with
24 the amount of gas that would occur at the higher -- gas
25 production that would occur at the higher rate, we make a

1 better use of the reservoir energy that remains by produc-
2 ing at the lower rate.

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

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

11 Q Among operators and wells within Gavilan
12 Mancos itself?

13 A That is correct.

14 Q Do you have an opinion as to whether if
15 the Commission puts the high test rate allowables as the
16 producing allowables as the producing allowables for Gavi-
17 lan Mancos Pool there is the violation of correlative
18 rights with regards to operations in any other pools adja-
19 cent to or in the vicinity of Gavilan Mancos?

20 A Yes, there will be.

21 Q What is the basis for that opinion?

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

25 Q When you say the Bear Canyon Unit to the

1 north, you're looking at the Amoco Bear Canyon Unit that is
2 up in these four sections on this display?

3 A Yeah. We didn't get that outlined but
4 basically it -- it covers the -- pretty much the northeast
5 quadrant of 26 North, 2 West. It covers all of Sections 1,
6 2, 3 --

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

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

10 Q The north half of these.

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

14 Q What is your concern with regards to the
15 Bear Canyon Unit and the operations in Gavilan Mancos Pool
16 if the Gavilan Mancos Pool goes to the higher rate allow-
17 ables?

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

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

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

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

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

9 Q Let's address now the question of the
10 inflow from West Puerto Chiquito Mancos into Gavilan Man-
11 cos. Do you have an opinion as to whether that's occur-
12 ring?

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

21 Q Let's talk about Gavilan Mancos Pool it-
22 self, now, Mr. Roe. Have you made a calculation and do you
23 have an opinion at the higher rate allowable what the re-
24 maining primary life is for Gavilan Mancos?

25 A Well, at the -- during the initial

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

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

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

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

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

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

1 is indicated.

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

4 First of all, Mr. Roe, would you ident-
5 ify the first page of the exhibit and simply describe for
6 us how to read and understand the display?

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

13 Q You're summarizing the bottom hole pres-
14 sure test results?

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

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

1 tabulation.

2 A Okay, if we could just use the second
3 well down, that would be a well that's operated by Sun Ex-
4 ploration and Production.

5 Q This is the Loddy Well?

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

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

9 A Yes.

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

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

15 During the second measurement of bottom
16 hole pressure test which occurred on November 19th of 1987
17 --

18 Q This is the low rate test period.

19 A Well, actually the production that oc-
20 curred between June 30th and November 19th would have been
21 the higher rate of production.

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

24 A Yes.

25 Q And the final three will be the low

1 rate.

2 A Yes, sir.

3 Q All right.

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

6 So after we had produced at the higher
7 rate of production for a 4-1/2 month period, on November
8 19th, 1987, we measured the pressure again and although
9 it's not real clear on this tabulation, we shut both pools
10 in on November 16th and -- at 8:00 in the morning, and then
11 after 72 hours we measured the pressure on November 19th,
12 and the pressures you see under the BHP at +370 psia is the
13 pressures that I have arrived at by taking the pressures at
14 whatever datum they were measured and converting to the
15 +370, and for the Loddy No. 1 that was 876 psia on November
16 19th.

17 Q When we move to the next column we see a
18 -190?

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

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

25 A That is correct.

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

4 A Okay. During the low -- the second
5 phase of the production period, which began November 20th,
6 1987, and ended on February 20th of 1988, the wells were
7 shut in on February 20th and the pressure measured on Feb-
8 ruary 23rd. Again taking the pressure that was accumulated
9 and converted into a datum of +370 and converted that to
10 psia, the pressure in the Loddy had now declined to 786
11 psia.

12 Q The next column shows a -90?

13 A Yes, that is the --

14 Q What is that?

15 A That would reflect between November 19th
16 and February 23rd the second phase of the production test
17 resulted in a loss of pressure of 90 pounds during the
18 3-month period for an average of approximately 29.7 pounds
19 per month.

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

22 A I have included some wells from the West
23 Puerto Chiquito Mancos Pool basically to reflect their re-
24 lationship to the wells within the Gavilan Mancos Pool,
25 yes.

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

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

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

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

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

15 A Yes.

16 Q And what is that number then?

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

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

1 A Yes, it is.

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

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

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

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

18 That, compared to the initial phase,
19 which would be the high rate of production, the recoveries
20 from the reservoir were about a third; the average of all
21 17 wells was 2200 barrels of oil per pound and the range,
22 the individual well range, was 1050 to 3550.

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

25 A Page 2 is nothing more than just a base

1 map reduced to a scale that fits on 8-1/2 x 11 paper, and
2 with the orange coloring I've identified the wells that
3 were -- from which pressure measurements were taken during
4 the test phase.

5 MR. KELLAHIN: Mr. Chairman,
6 we move introduction of Dugan Production Corporation Exhi-
7 bit Number Three.

8 MR. LEMAY: Number what?

9 MR. KELLAHIN: Three, sir.

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

12
13 (Thereupon a brief discussion off the record.)

14
15 Q Mr. Roe, let me direct your attention to
16 Dugan Production Corporation Exhibit Number Four. It's
17 included in your legal size manila folder in a reduced copy
18 --

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

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

24 A Yes, it is.

25 Q And what is the source of the informa-

1 tion you used for this display?

2 A The pressures, first off, this display
3 is a plot of bottom hole pressure again at the datum of
4 +370 for many of the wells that we have pressure from
5 throughout the Gavilan Mancos and some in the West Puerto
6 Chiquito Mancos Pool.

7 It's a plot of that pressure versus cum-
8 ulative oil production from the Gavilan Mancos Pool and
9 we've transposed the plot for the gas/oil ratio throughout
10 the productive life of the Gavilan Mancos, and so that you
11 can identify points in time, above the gas/oil ratio curve
12 we occasionally state what month that is, each of the
13 months that's plotted, so between January 4th and January
14 5th of '85 each of the dots is an individual month through-
15 out that timeframe.

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

18 First of all, when we look at the verti-
19 cal axis, what have you plotted on this axis of the dis-
20 play?

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

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

1 A Yes, that is correct.

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

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

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

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

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

18 A Yes, that is correct.

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

21 A That is correct.

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

25 A Yes.

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

3 A Okay. Basically that reflects the
4 individual pressure point that we had in the Dr. Daddy-O at
5 that point in time and roughly that's a pressure of about
6 1720 and it occurs at a cumulative production of approxi-
7 mately 800,000 barrels of oil from the pool.

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

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

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

19 A Yes, and on the individual plots that
20 were handed out I think we've identified the Loddy pres-
21 sures in orange.

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

1 A Okay.

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

4 A Basically we were just drawing a visual
5 average through the pressure data we had during the produc-
6 tion from the pool that occurred up through about 2-million
7 barrels of oil. So during the initial 2-million barrels of
8 oil production the rate of recovery from the reservoir
9 averaged about 11,000 barrels of oil per psi loss in reser-
10 voir pressure.

11 Q When we get to that portion of the dis-
12 play that shows a change in slope from the former slope,
13 you've identified that with another dashed line?

14 A Yes, I have.

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

17 A Yes.

18 Q Okay. What have you shown here then?

19 A Well, basically, beginning at roughly
20 2-million barrels of cumulative production from the reser-
21 voir, which is from a point in time, that was approximately
22 in March or April of 1986 and you can get that time frame
23 from -- from the gas/oil ratio curve.

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

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

4 Q All right, this -- this date for January
5 '86 that's arrowed to the gas/oil ratio will also fit if
6 you take it on up and project it into the pressure decline
7 slope.

8 A Yes. Yes, that is correct.

9 Q All right.

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

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

17 A Yes, sir.

18 Q All right, let's go back, then, to Janu-
19 ary of '84 and have you describe what's occurring in the
20 Gavilan Mancos Pool up to this point in time in the re-
21 servoir.

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

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

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

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

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

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

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

21 A In fact the -- the rate of pressure de-
22 pletion from the reservoir occurred right around March or
23 April of 1986.

24 Q Show me on -- on the display approxi-
25 mately where the Commission took action in September 1st of

1 '86 to reduce the allowables in the Gavilan Mancos Pool.

2 A Okay, that basically is the --

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

6 A Okay.

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

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

25 Prior to September of 1986 the rate of

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

3 Upon the allowable reduction that occur-
4 red in September of '86 that rate of pressure decline chan-
5 ged to approximately 33 pounds per month and it gradually
6 worked its way on up again to 39 pounds a month, indicating
7 that the reservoir voidage was only temporarily restricted
8 by limiting the gas/oil ratio.

9 Q Prior to the Commission action in Sep-
10 tember 1st of '86 were you seeing a slope change occurring
11 in the reservoir at higher rates?

12 A Yeah, we actually experienced a change
13 in the rate of pressure depletion prior to the Commission
14 ordering a reduction in allowable, which is one of the
15 things that I think guided the Commission in ordering a re-
16 duction in allowable.

17 The actual point on this graph if we go
18 to a point along the gas/oil ratio curve to where it flat-
19 tens there.

20 Q Right here?

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

22 Q That would be September of '86 and that
23 is the point that the allowables were reduced and, as you
24 can see, by that point in time the pressure in the reser-
25 voir had gone from an average decline of 5 pounds a month

1 prior to, say, October of '85, it had begun declining at an
2 average of 30 pounds a month. And that pretty much is what
3 we think resulted in the shift in the pressure recovery --
4 or the oil recovery curve from 11,000 barrels of oil per
5 pound, which is reflected on the pink curve, to --

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

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

12 Was that a result of the Commission re-
13 ducing the allowable days?

14 A No, not -- no. The actual -- that slope
15 change had occurred prior to the Commission issuing the or-
16 der reducing allowables and pretty much that, the fact that
17 we had had a slope change and the pressure had begun de-
18 clining at 30 pounds a month was one of the things that at
19 least concerned me as an operator within the Gavilan and
20 there were other operators that were concerned that irrep-
21 arable damage would be done to the reservoir.

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

25 A Well, I wish that we could show the Com-

1 mission that but there were several things happening in the
2 reservoir and that's why I wanted to talk about the other
3 pressure graph that we'll have later in our exhibits.

4 We did see a slowing in the rate of
5 pressure decline, which you can't tell from this plot here
6 because about the time that the Commission issued the al-
7 lowable reduction we also had a pretty dramatic increase in
8 reservoir voidage, not only because the wells were increas-
9 ing in gas/oil ratio and free gas production, but also the
10 number of wells that were beginning to be placed on produc-
11 tion was really increasing.

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

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

24 Now about this same period of time one
25 other event that was aggravating matters in Gavilan was the

1 wells that the Canada Ojitos Unit operator were drilling to
2 address the, you know, the drainage issue from the -- or
3 his protective wells that are pretty much located within
4 what we call the pressure maintenance expansion area. It
5 would be the two western rows of sections in the Canada
6 Ojitos Unit. During this period of time those wells were
7 being drilled and being placed on production, and that re-
8 sulted in a tremendous change in the reservoir withdrawal
9 and to some degree you can see that by the distance between
10 the two points, the cumulative oil that occurs between any
11 one month, those distances becoming shorter and shorter, or
12 longer and longer, I'm sorry, it refers (sic) that we were
13 actually producing more and more from the reservoir.

14 Q What is your opinion as an engineer as
15 to what would have happened to the green slope in the ab-
16 sence of the Commission reducing the allowable?

17 A Well, had the -- had the Commission not
18 reduced the allowable, I -- I haven't really followed that
19 thought all the way out, but my guess is that the reservoir
20 pressure would have been depleted by now. I didn't follow
21 --

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

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

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

7 A Okay, that -- that pretty much reflects
8 what happened during the -- the time that the production,
9 or the initial phase of the production test that the Com-
10 mission ordered.

11 Q This is the high rate test period.

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

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

25 A Yes.

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

3 A Yes, it is.

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

6 A Well, basically they -- during the test
7 period we saw the wells within the Gavilan Mancos Pool ac-
8 tually perform in two different manners.

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

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

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

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

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

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

21 A Yes.

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

25 A Yes.

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

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

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

15 A Yes. Yes, I do.

16 Q I have taken a copy of the Proponents
17 Exhibit Number Twenty and put it in front of your Exhibit
18 Number Four for a moment so you can aid me in an explana-
19 tion of the basis upon which you were making the testimony
20 in March of 1987 concerning what you found to be a pressure
21 loss in terms of pounds per year in the Canada Ojitos Unit.
22 Would you tell us the basis upon which you made that state-
23 ment?

24 A Well, I -- I used data that pretty much
25 was provided to me through my review of -- during this

1 period of time I worked, I don't think it's any secret,
2 I've worked very closely with Mr. Greer and had access to a
3 tremendous amount of information and I -- during this time
4 frame we were concerned with Gavilan declining at 5 pounds
5 a month where prior to that the unit had declined at a
6 considerably lower rate. So --

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

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

1 '80, does reflect what was happening within the West Puerto
2 Chiquito -- or the Canada Ojitos Unit, the pressure main-
3 tenance project, and that was an average of about 11 pounds
4 per year during that time frame, and we had, at the time I
5 quoted the 20 years, I think that was 1987, and I probably
6 stretched 17 years just a little but we still had no reason
7 to think the pressure wasn't performing along those trends
8 because of our continued observation of the pressure in the
9 gas cap area.

10 Q Taking that information, now, and inte-
11 grating it with the information you have observed and ana-
12 lyzed concerning the pressure test period, do you see a
13 pressure barrier between the pressure maintenance project
14 itself and the expansion area and Gavilan on the other
15 side?

16 A No, I don't. In fact I think that my
17 explanation for the fact that during the high production
18 rate we start seeing where prior to the June 30th pressure
19 measurement all of the pressure data points fell within a
20 fairly reasonable range. In other words, you could take a
21 bracket and draw down through there, and we have pressure
22 data for many other wells that that are not on this plot.
23 I just -- but most of the other wells only serve to confuse
24 the plot, but we have lots of pressure data that prior to
25 19 -- June 30th of 1987, all wells within the Gavilan

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

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

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

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

24 Q Let's look at the gas/oil ratio plot,
25 now, Mr. Roe. Let me follow along with the pointer on the

1 gas/oil ratio plot and you tell me when I get to the point
2 where the Commission took action in September 1st of '86 to
3 restrict the gas withdrawals from Gavilan?

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

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

9 A The gas/oil ratio did increase.

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

12 A I don't believe so. In September we had
13 41 wells producing. In October there were 48 wells that
14 were producing. So between that one month period there
15 were 7 wells. Like I said earlier, this is a time period
16 that within Gavilan we had potential for 100 locations with
17 the wells drilling or well locations and the wells being
18 completed, and so the rate of withdrawal is increasing dra-
19 matically. Like I say, from September to October there
20 were 7 wells added plus 2 wells in the boundary area of the
21 Canada Ojitos Unit were placed on production.

22 Q Your analysis shows you that this in-
23 crease in gas/oil ratio is attributable to simply the in-
24 creased withdrawals from additional wells in Gavilan?

25 A Well, that's one of the reasons it went

1 ahead and inclined.

2 Q What are some of the other reasons?

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

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

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

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

23 A Well, the -- in December of 1986, I
24 didn't look at that particular month, but my guess is we
25 had 49 wells in December and in January there were 53 wells

1 producing, and so I feel probably what you're seeing here,
2 because this reflects total from the pool, where there was
3 some additional wells placed on production, 4 additional
4 wells, that some of those wells coming on at lower gas/oil
5 ratios would actually reflect a poolwide reduction in the
6 gas/oil ratio, which is a little confusing.

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

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

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

19 Q The two months?

20 A Yeah, the peak would actually be June of
21 1987 and the earlier bump would be May of 1987, and what --
22 the distortion that makes that gas/oil ratio curve jump up
23 there, and you see this on all of the gas/oil ratio curves
24 we've seen presented so far, there were some wells that --
25 I'll use Dugan Production as an example,

1 We had a pump stick and so during June
2 of 1987 we had no oil production because we, for one reason
3 or other, did not jump out there and replace the artificial
4 lift equipment immediately, which, considering that the
5 well averaged -- was averaging between 1 and 3 barrels per
6 day preceding that, there wasn't any great economic incen-
7 tive for us to -- to rush to do it. So during June we had
8 no oil production but we left the casing open to produce,
9 and so during June we had no oil and 1267 MCF of gas pro-
10 duction. Again a small volume but it reflects added gas
11 with no added oil.

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

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

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

25 A Well, pretty much that time frame is --

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

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

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

7 Q Right here?

8 A Yes.

9 Q This is July?

10 A Right.

11 Q August?

12 A August.

13 Q September?

14 A Right.

15 Q October?

16 A Yes.

17 Q November?

18 A Right.

19 Q December?

20 A Yes.

21 Q All right.

22 A Now, again, the significance there, and
23 again, I'm not sure why there was a distortion in June's
24 gas allowable or gas production with respect to oil produc-
25 tion, but if you contrast any particular operator's oil

1 production, gas production, and gas/oil ratio, which you
2 can do by looking in my Exhibit Number One, I present the
3 operator totals and again those are the production statis-
4 tics that are on file with the New Mexico Oil Conservation
5 Commission, the C-115 reports, but if you contrast what was
6 happening in any operator, April, May, June, you can see
7 that the shift in oil and gas production was not, in my
8 opinion, related to what was happening in the reservoir;
9 probably it was something more mechanical.

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

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

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

24 So I have not dug into it to the degree
25 that I probably would like to, but I do feel the gas/oil

1 ratios that are depicted with May and June, are a little
2 misleading and to compare what happened to the pool gas/oil
3 ratio during the high rate of production to the May and
4 June to the May and June allowables, it was -- it could
5 leave with you with the misguided idea of what was happen-
6 ing in the reservoir.

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

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

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

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

22 A During the -- that was a 3700 barrels of
23 oil per pound, and again I stress, I found that, I guess
24 there's a real need to qualify all of your numbers. but
25 that is an eyeball average, that's not a mathematical aver-

1 age of that data, but it does represent the trend estab-
2 lished by that group of wells.

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

5 A I believe that the shift in the range
6 between wells that we now see within Gavilan, and the rela-
7 tionship of the recovery efficiency in terms of barrels of
8 oil per psi pressure loss, my explanation for that is that
9 the wells that are located in the general proximity of an
10 outer boundary of Gavilan, that you could receive a pres-
11 sure support. I believe they are receiving pressure sup-
12 port. Wells that are located towards an outer boundary of
13 Gavilan or within the gut of Gavilan that aren't a same
14 proximity to a possible pressure support, it is more evi-
15 dent to me that they aren't receiving a pressure support,
16 so pretty much the wells identified by the yellow trend are
17 going to be how the heart of Gavilan performs under a high
18 rate of production. The wells in the blue trend would de-
19 pict pretty much the future performance under unrestricted
20 rates of production of wells towards the outer boundaries
21 of Gavilan.

22 MR. KELLAHIN: Mr. Chairman,
23 at this time we would move the introduction of Dugan Pro-
24 duction Corporation Exhibit Number Four.

25 MR. LEMAY: Exhibit Four into

1 the record without objection.

2 Q Were you present in the hearing room
3 this week, Mr. Roe, when Mr. Elkins identified and describ-
4 ed Proponents Exhibit Number 36?

5 A Yes, I was.

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

8 A Yes, I've been here.

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

13 A We're basically identifying a rate of
14 pressure change. In this particular paper they were relat-
15 ing it to psi per minute but it would be similar to what
16 we've been talking about so far in the rate of pressure
17 change within the pool, and that's what they were, I'm sure
18 trying to approximate, is draw a relationship by reservoir
19 pressure change to something they could do in the labora-
20 tory.

21 Q And Fawcett (sic) and Muscat have got a
22 display here to show engineers that if we can get a large
23 enough pressure differential in operation conditions in a
24 reservoir and get above where the plot says recovery not
25 rate sensitive, we can get to a point in the reservoir

1 where the pressure differential measured in pressure versus
2 minutes, is going to be enough that we're going to improve
3 recovery out of this matrix if it's there.

4 That's what I understood this graph pre-
5 sents. Now I do want to qualify. I have not read this
6 paper. I am trying to operate with the understanding that
7 was given to me yesterday seeing this exhibit.

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

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

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

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

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

1 A We need to get a rate of pressure deple-
2 tion that would exceed 1 psi per minute.

3 Q You need one point.

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

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

20 Also, our --

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

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

1 Q I'm interested in the information on the
2 field observations of the core sample that was taken out of
3 the wellbore and analyzed in the laboratory and witnessed
4 by various members of the operating working interest Gavi-
5 lan group. Now which core is that?

6 A Well, the only core from the --

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

9 A Yes, the Mallon --

10 Q That's the one --

11 A -- Davis core.

12 Q -- that's the one that involved Mr. El-
13 lis.

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

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

22 A Okay. At the well, and again bearing in
23 mind this core was taken under the planning and direction
24 and guidance of a group of operators that formed the Engi-
25 neering and Geologic Study Committee, so basically, we all

1 paid for and we all planned and we all decided what inter-
2 val we would core, and because it was convenient to have
3 our geologist on location, he was there when we laid down
4 all nine cores and one of his specific assignments by me,
5 and he works directly under my supervision, and it was to
6 observe what the core looked like when it came out of the
7 core barrel before the roughnecks worked it down and got
8 all of the mud off of the rig floor.

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

12 Q What was then done with the core?

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

18 At that point it was observed during a
19 meeting of operators; the Geologic and Engineering Commit-
20 tee members that could make it were there to observe the
21 core.

22 Q And what were the reported observations?

23 A Well, at that point in time there was
24 still very little oil, in fact none, that had bled from the
25 matrix of the core. In fact that was one of the reasons

1 that the Engineering and Geologic Study Committee initially
2 decided that they wanted to, as part of the report we
3 wanted to photograph this core under a fluorescent light,
4 is because the only oil fluorescence that we saw when we
5 exposed the core to a black light was a very fine boundary
6 that existed between the very fine sand lenses. In other
7 words -- I say fine, very thin, there were no thick sands.
8 We're dealing with a core that is many, many, many layers
9 of very fine grained, highly calcareous cemented sandstone,
10 very low permeability in the matrix because of the
11 calcareous ce-menting, and interbedded with very, very thin
12 shales.

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

1 oil producing reservoirs.

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

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

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

10 MR. KELLAHIN: We have some
11 more.

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

14
15 (Thereupon a recess was taken.)

16
17 MR. LEMAY: We shall resume
18 with the testimony of Mr. Roe. Mr. Kellahin?

19 MR. KELLAHIN: Thank you, Mr.
20 Chairman.

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

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

1 terms of that point?

2 A The actual gas/oil ratio is -- is the
3 gas/oil ratio that existed during that month. The cumula-
4 tive production that it's plotted against would be an aver-
5 age cumulative for the month. In order to check that num-
6 ber you would have to look at the cumulative at the end of
7 the month plus the cumulative at the start of the month and
8 divide by 2, and that would give you an average cumulative
9 that would approximate the cumulative at the middle of the
10 month and the only reason that that would be real important
11 is if your gas/oil ratio is inclining at a significant
12 rate, which in some parts of these curves it is. It would
13 shift where you plot it if you plotted it at the end of the
14 month.

15 Q That's how you plotted it.

16 A Yes.

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

20 A Yes, it is.

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

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

25 A We -- we attempted to core all of the A,

1 B and C. We missed our core point just a little and only
2 got the lower part of the A, but all of the B and most of
3 the C.

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

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

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

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

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

1 A Yes, it is.

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

4 A Yes.

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

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

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

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

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

20 The completion report filed with the
21 state showed that the well was completed on July 30th of
22 1987 and the -- from the production records it began pro-
23 ducing in August of 1987 and for the most part, the month
24 of first production is intended to represent the month that
25 it was placed on production and sustained production. If

1 it produced one month and then was shut-in for a long time,
2 I more than likely would present the month that it resumed
3 producing after that long shut-in period.

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

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

18 The letter "B" would identify spacing
19 units that were developed on 320 acres, which was the ef-
20 fective spacing unit during the temporary pool rule period,
21 and the letter "C" is -- identifies wells that are along
22 the western edge of Gavilan in an area that the Commission
23 has spaced, basically a 310-acre spacing unit, plus an ir-
24 regular sized section which results in approximately a 505-
25 acre unit.

1 Q The next column tabulates the produc-
2 tion for the high period, test period?

3 A Well, what it does, is it reflects
4 whether or not I feel that these wells were limited by
5 production allowables during the high rate of production,
6 and I would indicate a well as being restricted by allow-
7 able with an "X". The dash would indicate it was not re-
8 stricted.

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

13 A No. There, in my opinion there were no
14 wells that produced at rates that were restricted by allow-
15 ables during the high rate of production period.

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

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

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

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

4 A That is correct.

5 Q For Amoco we find none.

6 A Right.

7 Q For Dugan we find none.

8 A That is correct.

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

11 A Yes.

12 Q When you look at Mallon Oil you have 5.

13 A Yes.

14 Q Meridian has 3.

15 A Yes.

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

18 A That's correct.

19 Q Mobil out of 6 has 2.

20 A Yes.

21 Q Reading and Davis out of 2 has 2.

22 A Yes, Reading and Bates would have 2.

23 Q When we look at Sun Exploration and De-
24 velopment Company, out of their 28 they would have 16 wells
25 that would be restricted at the lower allowable rates.

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

6 And just for easy comparison, the allow-
7 ables during those periods are again reflected at the top
8 of the column.

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

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

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

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

24 Q Mr. Roe, have you taken that information
25 from a study of this particular testing period and drawn

1 any comparisons in terms of the relationship between which
2 operators are benefited and which operators are not bene-
3 fitted if the higher test allowables become the allowables
4 in Gavilan Mancos?

5 A Yes, I have.

6 Q Did you prepare, or cause to be pre-
7 pared, Exhibit Number Six?

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

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

12 A Okay, on Exhibit Six what we've done is
13 taken the actual production that was reported on Commission
14 Form C-115 for the periods July, August, September and Oc-
15 tober, for one period, and compared that production to a
16 form upgraded that would be December through March, Decem-
17 ber '87 through March of '88, and then we basically con-
18 verted the production during the first production phase,
19 any individual operator's total production as it relates
20 to the pool total production in the high rate period and
21 then we've taken a look at that same percentage of the
22 total pool production in a low rate period, and the num-
23 bers you see on this graph represent the difference that an
24 operator would have of total pool production in the high
25 rate period as compared to the low rate period.

1 Q When we look at the vertical scale on
2 Exhibit Number Six and we find the zero point on the ver-
3 tical scale, what is represented by the zero line?

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

8 Q And Gavilan Field is the Gavilan Mancos
9 Pool?

10 A Yes, it is the Gavilan Mancos as identi-
11 fied by the state records.

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

15 A It would reflect that they actually
16 during the high rate of production compared to the low rate
17 of production, they would have 3.13 percent less of the to-
18 tal pool; for instance, Sun during the high rate of produc-
19 tion would -- their -- their production would account for
20 38.84 percent of the total pool production, where during
21 the low rate of production they would account for 41.97
22 percent of the total.

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

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

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

7 Q When we look at Hixon's share of produc-
8 tion what happens to Hixon's share?

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

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

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

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

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

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

25 A Yes, sir.

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

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

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

11 A Well, the percent of the pool production
12 that he did produce during the high rate of production was
13 29.5 percent.

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

16 A Well, Meridian would be the only other
17 operator to benefit during the high rate of production ver-
18 sus the low rate, and they actually increased their per-
19 centage by .49 percent.

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

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

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

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

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

8 Would you start first, sir, with Exhibit
9 Number Seven and identify that exhibit?

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

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

25 The wells that I've colored with an

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

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

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

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

19 A That is correct.

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

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

24 Q Mr. Roe, let me direct your attention to
25 Exhibit Number Eight, sir. Would you identify and describe

1 that exhibit for us?

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

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

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

13 There are 23 wells that actually a de-
14 crease in oil rate during the high rate production test.

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

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

24 Now, again, I'm trying to be real care-
25 ful that we're not comparing producing days or volumes.

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

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

6 MR. LEMAY: The record accepts
7 it without objection.

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

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

17 Now this is a little interpretive be-
18 cause if the well was on a production decline prior to the
19 high rate of production, what I'm comparing it to as it
20 comes back on production at the lower rate, the second
21 phase, is not exactly the same rate that it was producing
22 prior to the test, but the rate it would have produced at
23 had it continued to decline at the trend established prior
24 to the test, and so these are wells that I feel their pro-
25 duction decline, or ability to produce, changed as a re-

1 sult of having the high or the initial production phase.

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

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

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

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

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

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

19 Within this package there's 27 wells of
20 the 74. While we're getting set up, because the production
21 curves when we'd reduced them to the scale we had to in or-
22 der to make them reproducible easily, some of the informa-
23 tion became not as clear, and so out of the 27 wells that
24 are within this package, we have blown up or taken advan-
25 tage of the larger scale to try to talk through some of the

1 things that we see.

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

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

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

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

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

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

18 A Okay. This particular well is one that
19 I -- that would have been shown on the previous three
20 exhibits and it would have -- this well location would have
21 been colored yellow, indicating that the -- it did have an
22 increase in gas production during the high rate of produc-
23 tion test, which on this curve I've identified the gas with
24 the green curve and the oil with the red curve and the
25 gas/oil ratio with the blue line and what I reflect here is

1 just so you can see what was necessary for me to say this
2 well did have an increase in gas production and when you
3 compare the -- basically the July through November data in
4 green to what we had before, now, this particular well, we
5 have some awfully misleading results when we compare July,
6 '87 to -- the high production period to immediately before,
7 because this is one of the wells that pretty much the first
8 six months of '87 was -- was restricted to a maximum gas
9 rate of 100 MCF a day by the OCD because leading into 1987
10 it was pretty seriously over-produced as a resulting of
11 some production prior to 1987.

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

17 You can also see the fact that the oil
18 production jumped up pretty dramatically, which would ex-
19 plain why this well should have been colored green on Ex-
20 hit Number Five because it also had an increase in the oil.

21 Now this is one of the wells that I feel
22 suffered some -- or I call it suffered, It reflects a re-
23 duction in its ability to produce during the second phase
24 of the production test. For instance, the December, Janu-
25 ary, February, March data on the oil and the gas would re-

1 flect much lower rates than -- and again this is a little
2 hard to compare because immediately preceding the test the
3 well was not producing at the representative allowable for
4 the Gavilan Mancos Pool. It was being restricted to a
5 maximum 100 MCF a day Mallon total production, but if you
6 can take a look at the rate of production, say, during, oh,
7 January, February and March, and admittedly, what we're
8 plotting on this curve is total barrels of oil, what, say,
9 January, the well actually only produced six days for a
10 daily average of 118 barrels a day, and it produced, or it
11 probably had the potential to produce at quite bit higher
12 rates than that prior to the initial test period.

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

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

22 My purpose in including some of this
23 pressure data was not to tell you anything about the well
24 other than it's communicated with something else in the
25 reservoir, and the information on this sheet that tells me

1 that is basically the last two pressure points on this
2 tabulation. Say, for instance, the well had been left
3 shut-in after the pool was brought on production following
4 the shut-in period at a shut-in time of about 64 hours on
5 this shut-in time, all wells within the Gavilan Mancos Pool
6 were returned to production and at 25 hours later this well
7 started showing a pressure decline. Now, admittedly, it's
8 only 2 pounds but considering that it had at 982 pounds
9 from basically 76 hours through 87 hours, I feel probably
10 the 2 pound drop reflects that 25 hours after the pool was
11 placed on production, this well, even though it was still
12 shut-in, started showing up some effect of something going
13 on somewhere else, and all that I intend to show with that
14 pressure information.

15 Q Let's turn to the Mallon Well, it's the
16 1-11 Well?

17 A Yes.

18 Q Howard 1-11.

19 A That would be the third well in this
20 package.

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

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

25 A Okay. Well, basically this is a well

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

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

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

13 A This is the Howard 1-11 Well.

14 MR. DOUGLASS: 1-11.

15 A Yes, sir.

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

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

1 Babbit No. 1.

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

8 For instance, the first sheet that is
9 the section with the Dr. Daddy-O would be data that we re-
10 corded, and again, Dugan Production actually did this work
11 with McHugh as the operator just prior to Sun purchasing
12 this well. Early in the -- or late in June of 1986 we had
13 a pressure bomb on this well and this well did not really
14 commence producing under a sustained basis until September,
15 1986, so this is at a point in time that this well was re-
16 flecting a production decline not as a result of production
17 in this well but as a result of production from somewhere
18 else in the reservoir, and the pressure recording equipment
19 that we were using to record this data with was a very sen-
20 sitive bellows-type pressure bomb that has the accuracy and
21 ability to measure the pressure implements we're showing
22 here, so there should be no question as to this being ac-
23 tual data, it's well within the range of the tool.

24 And what I point out is, on the first
25 page there was a period that 1.9 psi per day was the rate

1 of pressure decline in this well with this well shut in.

2 On the second page I've got some addi-
3 tional data that shows how well this well responds to some-
4 thing else in the reservoir. I have not, for the purpose
5 of this hearing, attempted to explain of these changes al-
6 though you can see that we, in the latter part of June and
7 early part of July, the rate of pressure change actually
8 approached 8.2 pounds per day. It later takes a change of
9 1.9 pounds per day, and again, presumably, there's some-
10 thing going on somewhere in the reservoir that's causing
11 these changes.

12 So what happens conversely is if we pro-
13 duce this well at a high rate versus a low rate, it is also
14 going to affect something somewhere else in the reservoir
15 here. We're just trying to draw communication with the re-
16 servoir here.

17 MR. DOUGLASS: Could you re-
18 peat those declines in production? I can't read them on my
19 copy here.

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

25 During the -- on the second page, the

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

3 The initial rate of decline, say, July
4 9th -- or 10th and 11th, so that was actually July 9th and
5 10th, the well was declining at 8.2 psi per day. Now what
6 makes that a little confusing is we have a scale change
7 there. Really this -- this middle part of the curve, with
8 respect to this, it's just a continuation of -- of this
9 curve.

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

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

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

17 A Anyway, so 8.2, the first part of this
18 production graph, and it continues on the second part with
19 8.2 psi per day, and then something happened in the reser-
20 voir between July 9th and July 10th, and it looks like the
21 early part of July 10th, and the rate of pressure decline
22 at the Dr. Daddy-O decreased to 1.9 psi per day.

23 So again, nothing happened in the Dr.
24 Daddy-O. That well was shut in and we had a pressure bomb
25 in the hole; we were just observing what was happening to

1 the pressure in this well, because of something else in the
2 reservoir.

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

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

18 A It tells me that the -- that any one
19 well's ultimate recovery from the reservoir is going to be
20 totally dependent upon its ability to produce reserves com-
21 petitively from the reservoir, and they could very easily
22 be violated if for some reason or other, whether it's al-
23 lowables or mechanics or anything, if you shut a well in,
24 that point of the reservoir is going to continue to produce
25 as we -- we've displayed with these two exhibits. That

1 rate of pressure decline correlates to production and not
2 production from the well, but from that point in the reser-
3 voir moving somewhere else in the reservoir, resulting in
4 that pressure drop. So that number can be converted -- I
5 won't say that.

6 Q Let's go on to the next display.

7 MR. DOUGLASS: I'll ask you
8 again.

9 A I'm sure you will.

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

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

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

22 A Red and yellow.

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

25 A Okay. The Homestead Ranch No. 2 will be

1 just a little bit on into the package behind the Dr. Daddy-
2 O.

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

5 A This would be a well that I felt exhib-
6 ited an increase in gas production and sustained a reduc-
7 tion in its ability to produce following the high rate of
8 production test. It would have been colored yellow and
9 purple on the -- the maps.

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

17 Again, this well was not producing when
18 we were recording these pressures and the pressure decline
19 you see in this well is because of production somewhere
20 else, and early in the survey it is .24 psi per day; some-
21 thing happened. I just picked out two wells that were
22 placed on production that may explain it. The production
23 decline approached a 2.2 psi per day. A little later I see
24 the pressure starting to build up and I have also identi-
25 fied an event in the reservoir which was the shut-in of two

1 wells that probably explains that pressure increase, the
2 point being that this is very well pressure communicated to
3 other points in the reservoir.

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

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

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

25 A Yes. That's just a couple of more wells

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

15 Q Mr. Roe, having studied the Gavilan
16 Mancos production for years, having analyzed the informa-
17 tion from the bottom hole pressure tests, the high rate and
18 the low rate production information, do you have a recom-
19 mendation to the Commission as a petroleum engineer
20 actively involved in the Gavilan Mancos, as to how in the
21 absence of pressure maintenance the operators in Gavilan
22 Mancos can operate that pool for the remaining life of that
23 pool?

24 A In the absence of the unitized effort,
25 my feeling is that we have to have some sort of control on

1 allowables in order to protect correlative rights of all
2 operators within the Gavilan Mancos Pool.

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

9 A Yes, I have.

10 Q And what is that recommendation?

11 A Well, from the standpoint that we do see
12 some wells making a more efficient use of the reservoir en-
13 ergy at the higher rate, in other words the gas/oil ratio
14 (not clearly understood), it is my recommendation that in
15 the event an operator has that belief, that he be allowed
16 to produce -- that the pool rules be modified such that we
17 would -- it would provide an operator basically an excep-
18 tion to statewide Rule 502, Subsection 2, and we would pro-
19 pose that any one well would be allowed to be -- to produce
20 at his -- whatever rate he desires until he's four allow-
21 ables over produced, and at that point he would be shut in
22 until he balances his allowable. That way he would be able
23 to make more efficient use of the reservoir energy and min-
24 imize the impact upon correlative rights.

25 MR. KELLAHIN: Pass the

1 witness, Mr. Chairman.

2 MR. LEMAY: Mr. Douglass?

3 MR. DOUGLASS: Thank you, Mr.
4 Chairman.

5
6 CROSS EXAMINATION

7 BY MR. DOUGLASS:

8 Q Mr. Roe, you've mentioned several times
9 the term correlative rights. How do you determine correla-
10 tive rights, or what is your standard for correlative
11 rights?

12 A I use the guidelines as I understand
13 them, and that's that each lease and working interest
14 owner, royalty owner, should have an equal opportunity to
15 recover the reserves and the reservoir energy that is at-
16 tributable to that parcel of land.

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

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

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

25 A There has been a tremendous amount of

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

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

13 A That's my feeling, yes.

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

17 A No, sir.

18 Q What should be the standard for deter-
19 mining, then, what -- how an administrative body should
20 prorate an area?

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

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

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

5 It doesn't make sense that a set of par-
6 ameters, whatever they are, would only affect a few wells,
7 or at least to me it doesn't make sense.

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

11 A Yes.

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

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

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

23 A That would be approximately right, yes,
24 sir.

25 Q Now how much of that production or,

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

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

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

12 A Not any that I picked up as being signi-
13 ficant production, no.

14 Q And if I look at your Exhibit One here,
15 I can see in January of -- perhaps you could tell me when
16 you think the -- I can see in January of -- of '85 the cum-
17 ulative production had been about 643,000 barrels from Gav-
18 ilan Mancos, is that right?

19 A Yes, sir.

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

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

25

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

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

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

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

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

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

21 And just in January of '86 I see that
22 the area that we're talking about, let's use December of
23 '85, had produced 1.520-million barrels, is that correct?
24 In other words, if I go to your graph that you have --

25 A Yes, sir.

1 Q -- and go down to the cumulative produc-
2 tion at that time, it would be about 1.5207.

3 A Yes, sir.

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

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

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

11 A Yes, sir.

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

14 A I don't have those numbers, no.

15 Q Okay.

16 A Those numbers are available in our Exhi-
17 bit Number Two.

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

20 A We just have not actually added them up.

21 Q I was going to just check, they get
22 1.603-million barrels of cumulative production since the
23 expansion area went on. 1.603-million, so from the time
24 the expansion area went over, it was -- if you'll accept
25 the 1.603 subject to check, it produced 1.603- million bar

1 rels and the entire Gavilan Field produced about 2-1/2-
2 million.

3 A Yes, that sounds reasonable.

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

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

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

11 A I, quite honestly, when Mr. Lee was pre-
12 senting his testimony, I was thinking about mine.

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

18 A Well, --

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

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

24 Q I understand.

25 A -- I think it was his assignment to give

1 us a general idea as to what happens. I don't think he was
2 asked to do a model study of the reservoir.

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

6 A I don't know if there is.

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

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

11 Q Okay.

12 A -- was not --

13 Q I understand.

14 A -- paying attention when he was telling
15 us.

16 That's what it says, yes, sir.

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

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

24 Q Does that add up to 45.3?

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

1 again.

2 Q Did I detect when you put on your exhi-
3 bit with reference to Mallon's percentage of the production
4 during the normal rate time with an increase of 21.3 per-
5 cent, did you intend to infer that you thought that was not
6 fair?

7 A Yes, sir.

8 Q Do you have a calculator?

9 A I do.

10 Q Can you tell me what percent of the ex-
11 pansion area oil in place has been produced?

12 A I, yep, but I will comment, you know,
13 we're looking at the expansion area, a large number of
14 those wells didn't actually come on production until mid-
15 1987, so what comparing is -- five or six months worth of
16 production from those wells to two to three years of pro-
17 duction for wells in the Gavilan.

18 Q Well, I'm trying to -- I think I'm com-
19 paring all the production from -- that's the total cumula-
20 tive production from the expansion area, what I've got
21 here, not just the last four or five months.

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

25 Q In other words, you could have produced

1 more if you'd gotten the wells on earlier.

2 A Correct.

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

6 A You're right.

7 Q Okay, can you give me a percentage?

8 A All right. 7 -- using 19?

9 Q Using 19.0.

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

14 A Yes, sir.

15 Q Or the equivalent of it. How much during
16 that same period of time did the Gavilan Field produce?
17 2.4969 divided by 45.3.

18 A 5.5 percent.

19 Q 5.5 percent.

20 A That's subject to check, also.

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

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

1 A Which is probably all, approaching all
2 that you would expect from a primary depletion type reser-
3 voir.

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

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

8 Q Well, from August of '86 to present, ex-
9 cept for four months, you consider a small period of time.

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

11 Q All right, sir. Now, if -- comparing the
12 5.5 percent to the 8.4 percent, how much greater is the 8.4
13 percent than the 5.5 percent?

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

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

18 A Well, 21 percent more of the Gavilan re-
19 serves, yes, sir.

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

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

1 19-million barrels of oil, that is -- if that's the number
2 from him, I am not sure that that is a number I would agree
3 with, although I don't have a better number to give you
4 when you asked for one, but I think the number of oil in
5 place that you really need to use to compare recovery from
6 the expansion area would be basically the oil in place in
7 the unit because as I see the expansion area, it's the
8 withdrawal area for the unit that is injecting gas up
9 structure and producing oil down structure.

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

19 A Well. there's reasons for that.

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

22 A Well, primarily it's just a lower
23 gas/oil ratios that result because of the pressure mainte-
24 nance in West Puerto Chiquito, and so they don't have near
25 the rate restriction that results when you have the reser-

1 voir depletion that's occurring in Gavilan.

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

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

11 Q Well, let me ask you, is one of the fac-
12 tors that's used in unitization among the operators cumula-
13 tive production?

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

21 Q What you're saying is that this expan-
22 sion area, when it produces 52.7 percent more of its orig-
23 inal oil in place, it's able to drain the Gavilan area,
24 isn't it?

25 A So far that hasn't been the case and

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

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

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

19 Q Well, how could it not?

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

25 Q All, it would have to be lower across

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

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

5 Q Right, and you're saying that the pres-
6 sure has never been lower east of the boundary line?

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

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

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

20 Q After production started in the expan-
21 sion area, has the pressure been lower east of the boundary
22 line between Gavilan and the expansion area?

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

25 It's my feeling that generally the pres-

1 sure in the expansion area has been higher than the pres-
2 sure in Gavilan.

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

7 A Yes, that is.

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

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

12 Q Well, I'm -- I'm trying to get it limit-
13 ed to an area that you could check.

14 MR. DOUGLASS: This is a con-
15 venient time to stop or I can continue on, whatever you
16 prefer.

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

20
21 (Thereupon the noon recess was taken.)
22

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

1 Mr. Douglass.

2
3 CROSS EXAMINATION CONT'd

4 BY MR. DOUGLASS:

5 Q Mr. Roe, as I understood your presenta-
6 tion, you started off with some general propositions and
7 then you went into your exhibits, and I want to cover just
8 one or two of the general propositions.

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

12 A Yes, sir.

13 Q If the Commission finds that the barrier
14 exists where it's been shown by the Proponents, then would
15 it be satisfactory from your standpoint as far as the re-
16 commendation is concerned to at least have the same appli-
17 cable rules as far as production and development, and so
18 forth, are concerned, with regard to the expansion area and
19 Gavilan? That assumes that the barrier is there and that
20 the Commission so finds.

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

25 A Well, Mr. Douglass, my reasons for

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

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

16 A Well, they --

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

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

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

22 A Well, it's my understanding that
23 Mr. Greer has actually modified the West Puerto Chiquito
24 Mancos rules to be parallel with the rules regarding devel-
25 opment and allowables with Gavilan, but there is no differ-

1 ence right now.

2 A Okay, I want to make sure that if they
3 find the barrier is there, then as far as you would be con-
4 cerned, that they keep the current rules in as far as the
5 -- making them the same on both sides of that line is sat-
6 isfactory.

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

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

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

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

22 A Yes, sir.

23 Q And then later on you said that you
24 thought, looking at the July and August, September and
25 October periods, just looking at those periods might be

1 misleading because of some problems that may have been in
2 May and June of that year, is that correct?

3 A Yes, sir.

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

8 A Yes, sir.

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

11 A Yes, sir, it was.

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

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

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

23 A No, sir, I don't, because during that
24 period some of the very large wells in the pool were actu-
25 ally shut in or restricted in their permissible allowable

1 and so during that period of time the gas that -- what
2 little production they did produce, the gas/oil ratio was
3 high distorted and that will distort the pool's average
4 gas/oil ratio.

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

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

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

25 A Mr. Douglass, I think that that is the

1 period that some of these larger wells were being restrict-
2 ed to an artificially low gas/oil ratio because of an over-
3 produced status, and that forced the whole gas/oil ratio in
4 the pool to be high.

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

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

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

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

22 A Yes, it did.

23 Q Did the gas/oil ratio go down --

24 A Yes, it did.

25 Q -- in August? In September did the

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

2 A Yes, it did.

3 Q Did the gas/oil ratio go down?

4 A Yes.

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

7 A Yes, it did.

8 Q Did the gas/oil ratio go up?

9 A Yes, it did.

10 Q Did the next month the oil production go
11 down?

12 A Yes.

13 Q Did the gas/oil ratio go up?

14 A Yes, it did.

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

17 A Yes, sir.

18 Q Did the gas/oil ratio go up?

19 Q Did the next month the oil production go
20 up?

21 A Yes, it did.

22 Q Did the gas/oil ratio go down?

23 A Yes.

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

1 A Yes, it did.

2 Q And did the gas/oil ratio go up?

3 A Yes.

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

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

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

23 First of all, you recognize, then, in
24 the Gavilan, that if you produce at high oil rates, you
25 produce at low gas/oil ratio and that's a more efficient

1 use of the gas to produce the oil, is that correct?

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

4 Q Well, --

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

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

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

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

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

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

24 A Well, I'm one of the parties that thinks
25 that we have some gravity drainage and solution gas drive

1 in Gavilan Mancos Pool.

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

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

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

11 A Yes, sir.

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

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

21 Q Mr. Roe, you do believe that the produc-
22 tion from this area that we're dealing with here, that is,
23 the Gavilan area, doesn't come out of just the major frac-
24 tures, don't you?

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

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

3 Q All right, sir, and you would equate
4 the small fractures to being -- operating just like a mat-
5 rix, wouldn't you?

6 A No. Now during the break I did express
7 that the fracture system, it is lesser developed. The
8 microfractures and the small fractures are going to exhibit
9 a different performance than the large fractures but when
10 you use the word "matrix" I have a totally different con-
11 cept of what happens in the reservoir than I do in a frac-
12 tured shale.

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

15 A The Davis 3-15 was -- it penetrated the
16 Niobrara and if you look at the electric logs, it looks ex-
17 actly the same as the offsetting Fisher Federal or Howard
18 1-8 or Howard (unclear).

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

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

23 Q Well, I thought Mr. Greer's theory was
24 that there were these major fracture systems and these
25 tight blocks that sometimes would have as much as an acre

1 or 2 acres in them.

2 A Maybe even 40 acres.

3 Q Or maybe even 40.

4 A Yes, sir, and I --

5 Q All right.

6 A -- I subscribe to that theory also.

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

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

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

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

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

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

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

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

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

12 A Yes, sir, that was my conclusion.

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

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

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

25 Q Well, are you saying that determining

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

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

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

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

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

21 Did you examine that?

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

24 Q It shows the February to June '87 period
25 and shows what the voidage is as far as that period of time

1 is concerned in reservoir barrels to get a barrel of oil at
2 the surface.

3 A Yes, sir.

4 Q Did you disagree with that calculation?

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

7 Q And it shows that he got 30 -- it took
8 3176 stock tank barrels per psi during that period of time
9 to get the oil production up, is that correct?

10 A I --

11 Q That was the difference in --

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

14 Q And in what you call the high rate and
15 what we call the normal rate, then it would be 3662 stock
16 tank barrels per psi drop in pressure, (not clearly under-
17 stood.)

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

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

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

25 Q Well, this is. You understand that this

1 is not only the wells in Gavilan but this is in the expansion
2 area that showed this.

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

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

19 A That calculation would support that,
20 yes.

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

23 A Well, again, I'm aware that there are
24 some wells in Gavilan that are actually approaching the
25 category of gas well based on the last C-116 test; it

1 wouldn't surprise me if the Commission thinks they need to
2 be classified as gas wells.

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

5 A Not for this hearing, no, sir.

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

9 A Of the overall pressure in --

10 Q That's right --

11 A -- the unit?

12 Q -- the pressure in the reservoir.

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

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

17 A I, because of what I see on that tabu-
18 lation, plus the pressure data that was included in the 27
19 wells in my Exhibit Number Ten, I feel very, very certain
20 that that is a good measure of pressure throughout the re-
21 servoir because any time we can take wells like the Dr.
22 Daddy-O, the Homestead Ranch No. 2, or the Loddy No. 1, and
23 measure with those wells not producing, what's happening in
24 a reservoir, I feel reasonably certain when we shut those
25 same wells in, they are going to respond to reservoir pres-

1 sures, yes.

2 Q You think you have determined the aver-
3 age reservoir pressure from this.

4 A Yes, sir, I sure do.

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

8 A Yes.

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

11 A The production numbers here?

12 Q Yes.

13 A That would be just Gavilan.

14 Q Oh, is this just Gavilan production
15 here?

16 A Yes, sir, it is.

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

19 A Well, if you'll look, the pressure in
20 the unit wells is very similar to the pressure in the
21 Gavilan area wells; but you are right, I have unit well
22 pressures included in this tabulation, but I would have to
23 look, I really don't think that they could change the aver-
24 age, for instance, that is the reason I put a second aver-
25 age there that would exclude high and low pressure to see

1 if it was sensitive to a number being way out of range, and
2 for instance, you can see the same period it's changed 23
3 pounds considering all wells and 23 pounds considering (not
4 clearly understood).

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

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

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

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

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

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

1 13th -- February 23rd pressure survey, they're within 4
2 pounds of each other and they're around 950 pounds.

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

15 Q Mr. Roe, the gas/oil ratio during the
16 time of what you call high rate production, or the initial
17 test period, was about 36 percent lower than it was during
18 the restricted rate or the second test period, is that cor-
19 rect?

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

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

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

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

8 A 2183 MMCF?

9 Q Yes.

10 A Yes, sir.

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

12 A Yes, sir.

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

15 A About 485-million a month.

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

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

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

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

1 A That would be 313-million a month.

2 Q 313, and I believe you said 7 or 8 year,
3 8 years might be too long, why don't we use 7?

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

8 Q How many years?

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

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

18 A Yeah, but I think I said that that
19 wasn't probably realistic. I wouldn't use that to calcu-
20 late gas reserves.

21 Q Well, somebody might not use the pres-
22 sure, either, to determine how efficient a reservoir is,
23 would they?

24 A I would hope most reservoir people
25 would.

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

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

5 Q 26.

6 A Yes, sir.

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

9 A Yeah, but that -- that won't happen.
10 Like I say, I hope you weren't thinking I think that be-
11 cause I don't think that.

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

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

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

24 A That is correct and when I gave that I
25 qualified that the Canada Ojitos Unit wells were on there

1 only to develop a relationship to what's happening in Gavi-
2 lan.

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

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

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

10 A Yes, sir.

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

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

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

23 A I think that it's possible. I also
24 think that because prior to that time, though, 11,000
25 barrels of oil per psi, I think that occurred during a time

1 when there was only, well, the maximum of 34 wells in the
2 Gavilan, none in the expansion area, and none to the north,
3 and I personally feel that we were actually experiencing a
4 little pressure maintenance effect in the Gavilan Mancos
5 Pool at that time, and had we not had communication with
6 the West Puerto Chiquito Pool, we wouldn't have had the
7 rate of pressure decline of only 5 pounds a month.

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

14 A I hate using the word drainage. I think
15 we had some migration from West Puerto Chiquito into Gavi-
16 lan, possibly.

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

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

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

1 '86 to at the time that curve took its change there were 37
2 wells in May of '86, five months later, and in September,
3 '86 there was 41 wells. That was a time that everybody was
4 getting into the act out there.

5 Q If you included the production from the
6 expansion area represented by the pressure from the expan-
7 sion area, it would flatten out this curve, wouldn't it?

8 A Yes, sir, it sure would.

9 Q Do also --

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

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

19 A September was the first month, yes, sir.

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

22 A No, sir, they do not.

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

1 the same point?

2 A Yes, that's possible, but one of the
3 wells in that group is the well we have a real documenta-
4 tion of reservoir pressure performance with time and we
5 know that it's fairly well connected with the reservoir so
6 it's my feeling that the pressure in that well would re-
7 flect the pressure in that part of the well. The Loddy is
8 not a poor well. We've put in some of the wells that would
9 be slow to build up, or wells that are in that category.
10 Mobil's best well is down there, and so I feel it's going
11 to build up as fast as any of the wells, including the
12 Loddy and the High Adventure No. 1.

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

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

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

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

1 A Yes, sir. I had pressures well in the
2 unit, yes.

3 Q Was that the -- was that observation
4 well the A-23?

5 A No, sir.

6 Q Which well was it?

7 A It was the unit well -- it was one of
8 the gas injection wells. I'd be happy to give you that but
9 I don't have it at my fingertips.

10 Q You don't recall which well it was? It
11 wasn't A-23?

12 A A-23, no, sir, I know that.

13 Q I think it's nearer K-13. Was it K-13?

14 A It could have been, yes.

15 Q You don't recall. Let me ask you, with
16 reference to that, you said you'd worked closely with Mr.
17 Greer.

18 For some period of time in the unit
19 over-injection has been occurring with reference to that
20 operation, is that correct?

21 A There -- yes, sir.

22 Q And during that period of time the pres-
23 sure had been going down, hadn't it, in the unit?

24 A During the period of over-injection?

25 Q Yes.

1 A I don't know that.

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

4 A Yes, I did that --

5 Q Per year?

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

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

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

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

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

25 Q It certainly was not at the level that

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

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

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

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

11 Q Well, if the observation pressure was
12 1350 pounds and Mr. Lee says that the pressure in the unit
13 is 1900 pounds, that's -- that's not just a little, is it?

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

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

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

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

22 Are you saying that the conditions exist
23 on Exhibit Twenty, as shown on Exhibit Twenty, that there
24 is no barrier between West Puerto Chiquito pressure main-
25 tenance area and the expansion area and Gavilan?

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

4 Q Well, I'm asking -- my question is, if
5 on Exhibit Twenty, if that pressure profile is correct on
6 Exhibit Twenty, doesn't there have to be a barrier be-
7 tween the expansion area and Gavilan and the pressure main-
8 tenance area?

9 A No, sir, there does not.

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

13 A I think all of the maps I've ever seen
14 Mr. Greer present show that there's -- and I don't remember
15 if he's used the word "barrier" -- but there's always a
16 cross-hatched area with some question marks in it long be-
17 fore Gavilan ever -- ever existed, and so I think in my
18 mind and in Mr. Greer's mind, and in everybody's mind, I
19 think there's no question there is a reduced Kh part of the
20 reservoir, a reservoir that is not as high in transmissibi-
21 lity between the gas injection area of West Puerto Chiquito
22 and Gavilan. We see that in the tightness of the gas in-
23 jection wells. We know the gas injection wells are commun-
24 icated with wells within the gas cap by monitoring changes
25 in pressures with respect to different injection rates or

1 whether we're selling gas or not.

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

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

19 A I think that there hasn't been a signi-
20 ficant drop, no.

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

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

25 Q And your explanation for this pressure

1 profile on Exhibit Twenty, if it's correct, is that there
2 is an area there of some retardation but it's not effec-
3 tive to keep the flow from moving across.

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

6 Q All right. What other core did you look
7 at besides the 3-15?

8 A As a working interest owner in Bear
9 Canyon Unit I personally observed the complete core from
10 the Bear Canyon Unit No. 1, which cored all of the A, all
11 of the B, all of the B, and a good part of the C zone.

12 Q Is it what you call a C zone producer?

13 A It was initially. Since Amoco has re-
14 completed the well in the A and B, it's a little early to
15 tell, but I think early indications, it's only been on pro-
16 duction a week or two, but I think we could say we've
17 picked up additional production in the A and B.

18 Q Does it appear to be very much addition?

19 A Like I say, it's a little hard to tell
20 right now, but yes, I would say that there's no question
21 that we've got more oil and maybe even a little more gas.

22 Q On your Exhibit Five, do I understand
23 that you could actually determine the amount of acreage
24 that is -- I don't know what's the term used in New Mexico,
25 whether it's dedicated or proration unit or you say spacing

1 unit, you've determined the spacing unit for the -- for the
2 wells there, isn't that correct?

3 A That was the intention of that column,
4 yes, sir.

5 Q Were you aware that there's 35 -- excuse
6 me, 36,075 acres if you add up the spacing units that you
7 show here for a producing well?

8 A I haven't done that so I can't say that
9 checks, but that was in the ballpark --

10 Q Well, subject to check.

11 A Subject to check that's in the area
12 where we -- we feel the acreage within Gavilan, yes, sir.

13 Q And can I tell from your Exhibit One
14 what March production was for the field, as you call it,
15 Gavilan, that 44,170?

16 A It's March, 1988?

17 Q Yes, March, 1988.

18 A Yes, that is correct.

19 Q And that would be at the restricted rate
20 of production, is that right?

21 A Yes, sir.

22 Q How much would that be per acre?

23 A I'm going to leave my calculator at home
24 next time.

25 Q The Commission may want you to do that,

1 too.

2 A What was your acreage figure?

3 Q 36,075.

4 A That would figure out to be 1.2 barrels
5 of oil per day per acre.

6 Q 44,170?

7 A I'm sorry, barrels per month per acre.

8 Q 36,075, if that's correct off of your
9 exhibit, would be how much?

10 A 1.22 barrels of oil per month per acre.

11 Q Barrels of oil per month per acre. Now,
12 are you aware of the spacing units that have been assigned
13 to the producing wells, the 9 producing wells in the expan-
14 sion area? Maybe 10 now in March, I'm not sure.

15 A Well, they're all on 640 acre spacing
16 but I think there may be some sections that have got 2
17 wells.

18 Q So if they want two wells on a section,
19 they would have 320 for each well?

20 A That's the way I believe it would be
21 handled.

22 Q Would you accept, subject to check, on
23 the 9 wells that we see as producing, that they have 5120
24 acres for their spacing unit, and would you also accept,
25 and I think we can get the production -- my folks tell me

1 they actually got the production numbers out of your Exhi-
2 bit Two, and those --

3 A Mr. Douglass.

4 Q Yes.

5 A I'm not sure, there's at least 12 sec-
6 tions in there and I think the acreage may actually be just
7 a little more than that.

8 Q All right, give me whatever you want.

9 A I - I would use no less than 7680 acres.

10 Q 7680.

11 A But I think we're actually dealing with
12 a little more than that.

13 Q Well, 12 times -- you want to make it
14 bigger? Tell me how much acreage you want per well. Is
15 that 12 wells? How many wells in there?

16 A Well, just a minute and I'll check.

17 There's roughly 14 wells, I think, and I
18 get that knowing the last well drilled was No. 38 and I
19 think it started with Well No. 24.

20 Q Do you know how many producing wells
21 you've got in the expansion area?

22 A No, short of counting them, I don't.

23 Q Do you want to use 14?

24 A I don't know, you're asking the ques-
25 tions.

1 Q Well, I want to know how many acres are
2 assigned to producing wells in the expansion area. 640
3 would be the maximum, is that correct?

4 A Yes.

5 Q 14 wells, is that what you think the
6 number is?

7 A Well, can we tell him, Mr. Kellahin? It
8 appears to me that we have the exact number.

9 Q Our witness already testified it's 9. I
10 want you to tell me how many producing wells there are. If
11 it's different, we need to get the right information in the
12 record. I'm not sure his figures are for march, but you
13 tell me what you got for March.

14 A There is actually 15 wells that are com-
15 pleted in the two rows of sections that we identify as the
16 expansion area.

17 Q All of them got 640 or is it some 320?

18 A Well, I, for what I think you're trying
19 to do, I think it's more reasonable to think that we've got
20 two rows of sections that are 10 sections long, so what I
21 would prefer to use is 640 acres times 2 times 10.

22 Q You're going to get up to 20 now.

23 A Well, yes, I am.

24 Q You have 15 wells and now you want to
25 use 20.

- 1 A No, I'm talking about sections of land.
- 2 I -- I personally feel that, especially in the unit, that
- 3 one well will drain more than 640 acres.
- 4 Q Well, if you're going to determine how
- 5 much is being produced according to the spacing unit,
- 6 shouldn't you use the spacing unit?
- 7 A Okay, if you like, yes.
- 8 Q You've got 15 out there, you say you've
- 9 got 15 producing wells.
- 10 A Yes, sir.
- 11 Q All right, and 640 a well, how much --
- 12 how much acreage is that?
- 13 A Well, for your calculation let's use 640
- 14 acres, but there are some sections that have 2 wells.
- 15 Q I'm not going to quibble about that.
- 16 Give me 16 times 650. I'll let you have 640 for every one,
- 17 or the Commission will.
- 18 A Okay, that's 9600 acres.
- 19 Q 9600 acres. And would you accept sub-
- 20 ject to check that the expansion area produced 51,000 bar-
- 21 rels 420 in March? That sound about right to you?
- 22 A Certainly, yes.
- 23 Q You do know that the expansion area pro-
- 24 duced more in March than Gavilan, don't you?
- 25 A Yes, but that's what this hearing is all

1 about. With the lower gas/oil ratios that exist and the
2 voidage that is being created, that -- that should happen.

3 Q You better believe that's what this
4 hearing is about.

5 What's 9600 into 51,420?

6 A 5.35.

7 Q 5.35, so in March under the restricted
8 allowable rules, acreage assigned to 15 producing wells
9 received production of 5.35 barrels whereas the Gavilan
10 Field wells got 1.22 barrels per acre.

11 A Well, Mr. Douglass, this is one applica-
12 tion where we really do need to deal with reservoir voidage
13 and in that tabulation we would have to take into account
14 that the net reservoir voidage within the unit is not at
15 all comparable to the net reservoir voidage in Gavilan,
16 mainly because all of the produced gas less whatever (un-
17 clear) to return to the reservoir.

18 Q If you assume that the barrier does not
19 exist --

20 A Which I do.

21 Q If you assume that the barrier does ex-
22 ist, then the expansion area is producing 5.35 barrels of
23 oil per month per acre, versus 1.22 for the Gavilan.

24 A Which is one of the real benefits of
25 being unitized.

1 Q No, I think that isn't really. That's
2 one of the benefits of having restricted rates.

3 A Well, yes.

4 MR. DOUGLASS: Pass the wit-
5 ness.

6 MR. LEMAY: Mr. Lopez, do you
7 have any questions?

8 MR. LOPEZ: No, Mr. Chairman.

9 MR. LEMAY: Mr. Lund?

10 MR. LUND: Just one question.

11

12 CROSS EXAMINATION

13 BY MR. LUND:

14 Q Mr. Roe, on your Exhibit Two, the blue
15 folder, I was looking at the back for the production infor-
16 mation on the Canada Ojitos No. 22 Well, and I didn't see
17 it. Am I just missing it some place?

18 A Let me check real quick, Mr. Lund. I
19 think that's -- that would be the low rate Mancos well that
20 shows up in the barrier on Mr. Mallon's map that is actual-
21 ly completed in the Dakota formation.

22 The long term plans tendered by Mr.
23 Greer are to complete that in the Mancos but as of yet it
24 has only been completed in the Dakota, and tested, and I'm
25 not sure what his plans are to complete it in the Mancos,

1 but it has not been completed in the Mancos even though it
2 is represented as a Mancos completion on at least this map.

3 Q And the production information is not
4 contained in your exhibit?

5 A Well, Mr. Lund, it hasn't been completed
6 in the Mancos yet. It's only been perforated in the Dakota
7 and because of that I think probably the well has been shut
8 in since testing. I do know that Mr. Greer has given some
9 thought, and has actually circulated to the working inter-
10 est owners a proposal to equalize the Dakota and Mancos
11 right, so that the Dakota possibly would serve as a source
12 of gas for pressure maintenance, but there is no production
13 from the Mancos from Canada Ojitos Unit No. 22 yet. It has
14 just not been completed in the Mancos.

15 Q And your testimony was that it's very
16 small production from the Dakota, is that what you said?

17 A I don't remember quoting a number but
18 that is correct. That Dakota is not very well in that well
19 and the number I remember is about 120 MCF a day and about
20 1 barrel of oil a day.

21 Q And the Dakota production from that well
22 is not in here.

23 A No. I'm not sure where the Commission
24 carries that. It's probably going to be an undesignated or
25 Basin Dakota Pool. It won't be in the Gavilan Mancos Pool.

1 It's probably -- I don't know, I think
2 Basin Dakota Pool, so that's probably where it is.

3 Q All right. I just wanted to confirm it
4 wasn't in this (unclear.)

5 A That is correct. Any production would
6 not be from the Mancos.

7 Q Thank you.

8 MR. LEMAY: Additional ques-
9 tions of the witness?

10 Mr. Chavez.

11
12 QUESTIONS BY MR. CHAVEZ:

13 Q John, your exhibit on the West Puerto
14 Chiquito Mancos production statistics, is there a well
15 missing operated by Amoco, the Schmitz Anticline Well, in
16 Section 25 of Township 24 North, 1 East?

17 A Yes. In fact I'm afraid I didn't real-
18 ize until -- we didn't pick up the Schmitz Anticline or the
19 recent State Com CC or the Wishing Well, and so there are
20 three additional wells in the -- that general area,
21 although I guess the Wishing Well and State Com CC aren't
22 additional, or, you know, they're in the pool, so there are
23 three wells that are not included here. It was an uninten-
24 tional error. I just got wrapped up in West Puerto
25 Chiquito and Gavilan and forgot about the Schmitz

1 Anticline.

2 Q In your study of the bottom hole pres-
3 sures in the Gavilan Pool, did you find that the discovery
4 pool pressures were lower than they should have been in the
5 pool?

6 A Yes. We felt that the initial pressure
7 that we observed in the Gavilan 1 were approximately 100
8 pounds or so below what we would have anticipated virgin
9 pressure to have been.

10 Q What did you attribute that to?

11 A Well, at the original pool hearing Mr.
12 Greer testified that he felt that was evidence of -- of
13 depletion in West Puerto Chiquito and migration from
14 Gavilan to West Puerto Chiquito.

15 I feel that that's probably as good an
16 explanation as any. The development to the west in the
17 West Lindrith was very fair removed at the time Gavilan was
18 developed, so it's my feeling that we probably had some
19 migration into West Puerto Chiquito prior to the discovery
20 well, and that has been placed in the records.

21 Q On the first straight line you drew on
22 your graph on Exhibit Number Four at the top, does it ap-
23 pear to you that the wells that are producing both within
24 Gavilan and in the proposed expansion area are functioning
25 on the same type of pressure drop, same rate of pressure

1 drop, with the production of oil?

2 A Pretty much the top line I would say so,
3 yes, sir. Now, that's what I -- that's how I explained the
4 difference for the deviation of curves at the latter part
5 of the curve with the proximity of those wells to Gavilan
6 and the unit providing a pressure input.

7 But yes, up early in the curve the re-
8 servoir pressure in that area was very similar.

9 Q Is there some point on that curve that
10 you could estimate that what you term as pressure support
11 from the pressure maintenance project is visible and the
12 lines divide that give you your -- the two lines you end up
13 with?

14 A It really became apparent to me that
15 there was something happening when I put the three pres-
16 sure measurements on that were a result of the Commission
17 ordered test.

18 The last pressure that we have prior to
19 that, there's kind of a group of wells that would be, oh,
20 just past the December '86. We were noticing a change in
21 trend of some of those wells at that time, although I --
22 we had that prepared for an exhibit pretty much through the
23 green line at one time. We just added the July, November,
24 and February pressure points to it, and that's when we
25 first really figured out that something had happened.

1 So what I'm telling you, we really don't
2 have an explanation.

3 Q On your Exhibit Number six --

4 A Yes, sir.

5 Q -- you only used wells producing within
6 the Gavilan Pool proper. Did you make any estimations on
7 the change in total share of production including the pro-
8 posed expansion area wells?

9 A No, Mr. Chavez, we were -- again my
10 primary concern is with Gavilan and how the reserves will
11 be distributed in Gavilan, and you'll -- you'll note that
12 we left Amoco Production out of these calculations primar-
13 ily because Amoco really had no -- or very little produc-
14 tion during the high rate test, so what we were trying to
15 do here is reflect how the reserves would be distributed
16 within Gavilan, not necessarily the total pool.

17 Q Considering the issue of correlative
18 rights which I think you're trying to address with this
19 graph, might not we consider the problem of correlative
20 rights across what we consider the pool boundary?

21 A Well, I -- all of my conversations with
22 Mr. Greer on that are that he is willing to try to develop
23 a method of some sort so that we have similar pressures on
24 both sides of the boundary and we don't have a cross flow,
25 but that is about the only method to deal with correlative

1 rights, is try to stop the flow of unitized fluids into
2 Gavilan or Gavilan into the unitized areas.

3 And it would be something that we would
4 propose to take care of with -- with some other method. In
5 other words, the fact that gas is reinjected into the unit,
6 you'd have a different reservoir voidage on the unit side
7 than you do in Gavilan, so you don't have a similar situa-
8 tion in Gavilan that you do in West Puerto Chiquito.

9 I maybe didn't understand your question.

10 Q That's close enough. On your Exhibits
11 Seven, Eight and Nine, were there any changes that you
12 noticed within the proposed expansion area that might could
13 have been noted on these maps that weren't?

14 A Mr. Chavez, I -- given more time I want-
15 ed to look at the expansion area myself but I did not look
16 at the expansion area.

17 I do know that the gas/oil ratio was not
18 as near a problem in the expansion area as it is in
19 Gavilan, so they won't be the same, but I'm sure there
20 would be some differences.

21 Q You have stated a few times now that all
22 the gas produced within the pressure maintenance project
23 has been injected. Are you aware of any gas at all being
24 sold to El Paso Natural Gas from the unit within the last
25 year, two years?

1 A Yes, only during the high -- beginning
2 during the time that we were -- the initial phase of the
3 production test, the unit did sell gas for two reasons.
4 One, it is necessary to make some adjustments to keep the
5 pressure in West Puerto Chiquito a little more balanced
6 with the Gavilan and you can't do that by reinjecting all
7 of the gas, plus at the higher -- higher rates there was
8 quite a bit more gas from -- than we could reinject.

9 MR. CHAVEZ: Thank you, Mr.
10 Chairman.

11 MR. LEMAY: Additional ques-
12 tions?

13
14 RE CROSS EXAMINATION

15 BY MR. DOUGLASS:

16 Q Mr. Roe, with reference to the wells in
17 the expansion area, are you aware of what their deliver-
18 ability is as far as oil and gas is concerned?

19 A No, sir, I don't know the individual
20 wells, but the statistics are presented in my Exhibit
21 Number Two.

22 Q But you don't -- you don't have the --
23 you don't know or have available to you, as far as you can
24 tell within a reasonable time, what the deliverability is
25 of the wells in the expansion area. It's the figures you

1 don't remember.

2 A That is correct.

3 Q Do you remember what the deliverability
4 is of the Dugan wells in the Gavilan Field?

5 A Well, Dugan operates one well in the
6 Gavilan Field and so, yes, I do.

7 Q What is it?

8 A One barrel a day and about 35 MCF a day.
9 Now, Dugan does have interest in about 26 other wells in
10 the Gavilan.

11 Q 26 others. Who operates those?

12 A Various operators, not just one.

13 MR. DOUGLASS: That's all I
14 have.

15 MR. LEMAY: Commissioner Bros-
16 tuen.

17
18 QUESTIONS BY MR. BROSTUEN:

19 Q Mr. Roe, on your Exhibit Number Four,
20 that's the ones you have on the board before you there, are
21 all the pressures that are shown on this exhibit observed
22 pressures or are they some that are taken from the rainbow
23 map or by some other method that's devised by Mr. Greer for
24 pressure determination?

25 A All of the pressures here that are on

1 this map, plus I mentioned that I had so many more that if
2 I put on here, it would just confuse the map. It wouldn't
3 add to the story or actual measurements.

4 On occasion I might have measured a
5 fluid level to determine pressure, but generally these are
6 all on measurements.

7 Q You discussed the 72-hour shut-in period
8 briefly and it appeared from the exhibits that have been
9 presented thus far that pressures were continuing to climb,
10 that they're not stabilized in a 72-hour period, you said,
11 but anyway, you were taking these pressures field-wide so
12 that essentially it's comparing apples and apples, not
13 apples and oranges.

14 However, what would you anticipate what
15 would have been the change in any of your determinations
16 regarding pressure, pounds per square inch per barrel of
17 oil and so on and so forth, had these pressures continued
18 to be measured and the wells shut-in until the wells had
19 stabilized?

20 A Well, barring the major continued build
21 in the pressure, and it is my feeling that if they weren't
22 stabilized, in other words the build-ups that we did have,
23 were -- were increasing at different periods so that a lot
24 of the wells actually built-up. The Fisher Federal in the
25 last test built up completely in 9 hours.

1 There were wells that still had some
2 build-up ranging anywhere from 2 to 4 pounds a day, I
3 think.

4 We did not have build-ups in all wells,
5 though, and so generally we're trying to compare even the
6 wells we did have build-up, or at least the pressures I'm
7 using is the 72-hour pressure, so that it will be com-
8 parable with the 72-hour pressure from the previous test
9 and also the 72-hour pressures of the other wells in the
10 field.

11 Q I see. You also discussed briefly some
12 of the wells that would -- that are located along what the
13 Proponents have referred to as the barrier. The F-20 Well,
14 Well, COU No. 22 I believe is the one you said was complet-
15 ed in the Dakota, production rate of 1 barrel of oil a day,
16 and I forget how much gas. Was it a completion attempted
17 in the Mancos?

18 A Not yet. It's my understanding Mr.
19 Greer plans to do that.

20 Q But there's been no attempt at perfora-
21 tions or anything that you're aware of?

22 A That is correct. The Dakota is the only
23 zone that has been tested, as far as I know.

24 Q The -- the well just to the south of
25 that, the Benson-Montin-Greer G-32, (not understood) that

1 was submitted, Exhibit Number Five, submitted in -- earlier
2 this year, in the hearing early this year, they show the --
3 this well as having produced 7 -- now this is a figure that
4 was presented by Mr. Greg Hueni, I believe, 6000 barrels of
5 oil cumulative and the well was shut-in.

6 Do you know the status of that well and
7 whether or not that well is essentially depleting and what
8 reservoir is around it?

9 A This is probably something that Mr.
10 Greer could better answer. It's my understanding they had
11 a jelled oil stimulation and that he thinks there may be
12 some problems with that system, but beyond that, I -- I
13 don't know.

14 Q Well, perhaps I should defer these
15 questions to Mr. Greer, then.

16 A Yes, sir.

17 Q Okay, thank you.

18 A You'll get a better answer.

19 Q Thank you.

20 MR. BROSTUEN: That's all I
21 have.

22 MR. LEMAY: Commissioner Hum-
23 phries.

24

25

1 QUESTIONS BY MR. HUMPHRIES:

2 Q Why wouldn't the huge withdrawal of Gav-
3 ilan Mancos have made some kind of measurable response in
4 pressures on the decline curve, or the long stable pressure
5 curve in the pressure maintenance project, or the entire
6 West Puerto Chiquito, given that relatively dramatic amount
7 of new wells and large production and the relatively drama-
8 tic drop, if there's no restriction between the two?

9 A First off, I think to accept that the
10 pressure performance in the original area of the pressure
11 maintenance is truly represented by that long line covering
12 20 years where we have basically a point on each end, even
13 though that may approximate the pressure, we don't really
14 know that for sure and I am not positive whether or not
15 we've seen a pressure change in that original pressure
16 maintenance area.

17 My thinking is that maybe we have, but
18 Mr. Greer would probably be able to address that better
19 than I would. I quite honestly have concentrated my ef-
20 forts in the Gavilan portion of this pool and tried to keep
21 knowledgeable in the West Puerto Chiquito, but as far as
22 the bulk of the work goes, Mr. Greer has actually done most
23 of that.

24 Q Well. assume that we're not even talking
25 about 20 years. Let's say we're talking about approxi-

1 mately the same time as Gavilan Mancos came on, with the
2 absence of the alleged barrier, even with over injection,
3 wouldn't there have been some response expected?

4 A Yes, sir. I would expect that there
5 probably has been a change in pressure but I just can't
6 tell you how it's changed. I again have spent most of my
7 time in an area that -- that Dugan is the operator and left
8 West Puerto Chiquito up to Mr. Greer.

9 Q In the, well, in the discussion you have
10 in Exhibit Six you talked about the large percentage of
11 production of the Mallon wells, I think, yeah, the seven
12 wells that produced -- or had the advantage of some 21 per-
13 cent of the field production. Not respective of whose
14 wells they are, isn't it possible that some wells would be
15 better than others in that pool? I don't think anybody's
16 suggested that the entire Gavilan Mancos Unit as it exists
17 to date is totally homogeneous.

18 A Well --

19 Q I mean Pool, strike the word "Unit".

20 A Actually, presented on Exhibit Six is
21 the difference between the two -- two test periods. During
22 the high rate of production he actually from his wells pro-
23 duced 29-1/2 percent of the total pool production.

24 Q Well, my question is, though, regardless
25 of whose wells they are, isn't it possible that some wells

1 will be superstars and some wells will be duds?

2 A Sure, and that's just exactly what we
3 have in Gavilan. There is a big contrast between wells.
4 The problem I have is that we have an abundance of pres-
5 sure information, a large part of which I included in my
6 Exhibit Ten, which we did not devote the time to go
7 through, because a lot of it was pretty redundant, but
8 throughout the pool we see these wells are connected with
9 each other so well that what happens in one well will af-
10 fect another well shut in and so we have to, I feel, --
11 well, also my feeling is predicated on the fact that I
12 think the reason we have a better well is because that
13 particular spot in the reservoir is influenced by the
14 natural fracturing of the Mancos more extensively than
15 maybe a well that isn't so good, and so we're not actually
16 looking at a difference in reservoir quality as being re-
17 sponsible, the reservoir -- I didn't say that right. The
18 reservoir quality is better from the standpoint it's got
19 more fractures, but it's the fractures that actually make
20 the wells good wells or poor wells, as evidenced by the --
21 we talked a little bit about the Davis Federal 3-15. From
22 all appearances and log measurements and even looking at
23 the core, we saw fractures in the core. That should have
24 been a much better well. It's offset by some of the --
25 well, Mallon's wells and they're some of the best wells in

1 the pool. I don't think there should be any doubt about
2 that.

3 The problem we have is that those wells
4 are just left unchecked because they are better and because
5 of the communication we have throughout the reservoir as
6 documented with our pressure testing. It's conceivable
7 that one well will drain much larger areas than that which
8 is assigned to it.

9 Now, if it wasn't offset by wells that
10 could also produce their reserves, then I would say I would
11 not have quite the problem, but there is good wells in the
12 the reservoir. They just aren't as good as Mr. Mallon's
13 wells and so it's my feeling that if you let the good wells
14 produce all they can there's going to be a big violation of
15 correlative rights of the offset wells.

16 Q Well, one of the basic things I think
17 the Commission's responsibility is to statutorily protect
18 correlative rights, and I certainly didn't disagree with
19 your definition that that was the amount of reserves and
20 reservoir energy under one individual's land, or I guess
21 one lease or multiple leases.

22 Is that -- the way I interpreted your
23 testimony was that the Commission would need to accept that
24 that was equally distributed across all of Gavilan Mancos
25 Pool at this point.

1 A That's kind of the way I see what's
2 happening there in the Mancos formation, is the actual
3 storage capacity of the fractures is really very small.
4 Porosity, when you consider a fracture as dividing the
5 pool's pore space, to store oil in, and that's very likely
6 why you can see such a big fight over is there secondary
7 porosity or matrix porosity, is the amount of reserves that
8 are in place are very small because some of us feel that
9 it's primarily stored just in the fractures and they repre-
10 sent just a very small percent of the total bulk volume.

11 So I can't give you a number but, you,
12 know, maybe one to two percent of the total bulk volume is
13 all you have to store oil and gas in, if you subscribe to
14 the fact that there is no matrix.

15 The areas that are more intensely frac-
16 tured will have probably a little bit more oil in place
17 than the part of the reservoir that isn't heavily fractured
18 because of, you know, there are just more fractures, but
19 it's not going to be in relationship to that well's produc-
20 tivity. In other words, you could have a good well because
21 it's got good fractures, but it won't have an equal amount
22 more of reserves in place than a well that's not quite as
23 good.

24 Q One more question and then I'll be done
25 here. Is it logical then to assume -- it strikes me as un-

1 usual that that much circumstance or chance would find it-
2 self located in 7 wells out of 36,000 acres. Are you say-
3 ing that the laws of chance or probability converged on
4 those 7 wells?

5 A Well, you're talking to somebody who
6 just drilled poorest well in the field, too, right in the
7 middle out there. Yes, that's what happens.

8 Q It's just random luck?

9 A Well, I would like to think that it's
10 more than random. We, we being Dugan Production jointly
11 with BMG, conducted an areal photo survey of the area and a
12 Landsat study.

13 We have that that guides us quite a bit
14 as to where we locate our wells. We think maybe we can see
15 on the surface what may project to depth in the Mancos. We
16 have a lot of information put into the (unclear) but when
17 you get right down to it, we thought we were going to get a
18 good well with the Davis Federal 3-15 when we drilled it
19 and we chose that well to take some core from as an Engi-
20 neering Study Committee project.

21 I don't know that that discounts the
22 value of the core, that it's in a poor part of the reser-
23 voir. I think probably what we see in the core is the
24 matrix part of what the fractures are in. It would have
25 been nice if the well would have been a little better so we

1 could say, yes, this represents what we're producing from.

2 Q Thank you.

3
4 QUESTIONS BY MR. LEMAY:

5 Q Mr. Roe, on your Exhibit Number Four,
6 the one behind the proposed area, when you start getting --
7 we're talking about shortly after January, 1986, when you
8 start getting a change in the slope of the pressure curve,
9 you also seem to be getting an increase of a GOR and if my
10 memory serves me correctly, isn't that the approximate
11 pressure of the bubble point in that reservoir?

12 A It's awful close. The two bubble point
13 pressures that I have available, the sample that was taken
14 in the Canada Ojitos Unit from Unit Well L-11 had a bubble
15 point pressure of 1530 psia and the Loddy, which was a well
16 operated by McHugh at the time, has a bubble point pressure
17 of 1593 psia.

18 Q With my knowledge, and it's limited as
19 to reservoir energy mechanics, the GOR will go up when the
20 gas breaks out of solution, so you get at the bubble point
21 increasing GOR's.

22 A Yes, sir.

23 Q But would you have a decrease in effi-
24 ciency in the reservoir mechanism so that your pressure de-
25 cline would be greater per barrel produced?

1 A Yes, you sure would. Part of, you know,
2 I think we've all acknowledged that as the reservoir pres-
3 sure depletes we are going to be producing more and more
4 free gas and it's my feeling that with us getting a frac-
5 tured reservoir that's so massive in thickness, in other
6 words, we're dealing with something from top to bottom,
7 whether it's all productive or not, that we've been perfor-
8 ating about a 400 - 450 foot interval. It gives us -- and
9 then we turn around and stimulate that interval and it
10 gives us lots of room for gravity segregation to occur at
11 any point in the wellbore and so as we allow this gas to
12 evolve from solution, which I don't care whose bubble point
13 pressure you use, we're definitely below it now, you are
14 going to be producing more free gas and if we don't make
15 the best use of that gas, we will be wasting reservoir en-
16 ergy.

17 Q That's the other point, I don't know if
18 we can get into it now, but I think the problem that I
19 face, there are many of them, but the problem I see, and
20 correct me if I'm wrong, that we have two contradictory
21 points of efficiency.

22 One is that with the lower GOR's you've
23 got a more efficient reservoir but during that period of
24 high allowables the corollary of that was the exhibit
25 showing that greater amounts of oil were produced per

1 pounds of pressure drop and they just don't seem to fit in
2 my mind. I can't visualize that. If you have a voidage
3 that's -- that's less per barrel, your pressure drop should
4 be less. They should go hand in hand, shouldn't they?

5 A Yes, but we have some other things that
6 are cranked into this that -- in other words, if we were to
7 do a material balance on the reservoir, that's really what
8 we should do, but we don't know where the reservoir stops.
9 I myself have very good reason to believe that the area to
10 the north of Gavilan, primarily the Bear Canyon Unit, is
11 communicated with Gavilan. So prior to that area coming on
12 production, and it is just now doing that, I feel that area
13 probably was migrating towards Gavilan, and that is a
14 pressure inflow to the reservoir that we measure but we
15 don't account for and it shows up in the efficiency.

16 We also, I feel, properly received pres-
17 sure in the flow from the pressure maintenance project. We
18 even, you know, have measured pressure depletion in
19 Merrion's Krystina No. 1 in the southern part of the unit;
20 a very poor well but still exhibiting a pressure decline
21 inferring hydrocarbon flow from that point into Gavilan,
22 and these are things that, you know, it's very difficult
23 for me to account for that they will affect that, and --
24 because we do acknowledge that the in wells, some wells did
25 exhibit a lower gas/oil ratio. I myself am a little suspi-

1 cious that we're looking at something more of a mechanical
2 thing in the reservoir because of the gravity segregation
3 and once you get the oil moving it's better to keep it
4 moving or it may be somewhat analogous to a low pressure or
5 a gas reservoir with -- like a Dakota well in its later
6 stages. Even though there's quite a bit of gas left you
7 start having problems lifting the liquids from the well and
8 it's very common practice to open those wells up, blow them
9 to the atmosphere at a very high rate and get that fluid
10 moving. Then once it's moving you can get it into the
11 pipeline and hope the pressure doesn't go up and block you
12 off.

13 And that may be somewhat analogous to
14 what we're dealing with. We're dealing with a reservoir
15 that's within 500 pounds of what I or Mr. Hueni have used
16 as an abandonment pressure.

17 Q Well, given the performance of what
18 we'll call the superstars now, the superstars, the Howard
19 Federal, some of the Mallon wells, that seem to be the ones
20 that react the most to the increased allowable, they're the
21 ones that go from maybe zero to 10,000 barrels a month, and
22 in Mr. Weiss' terminology, that's lots and lots of oil; 10
23 percent of the production from the pool; just a rough
24 calculation, 100,000 a month, 10,000 from that well.

25 Is it possible that that well because of

1 its spider web network can draw from further away and it
2 can get some of that Bear Canyon oil with the higher
3 allowable but it's not capable of doing that with a re-
4 stricted allowable? Wide open does that draw from further
5 away? Is that the way it works with some of these oil
6 wells?

7 A Well, I -- I myself feel that that's the
8 way must be working because wide open, you know, unless I'm
9 grossly in error in how much oil per acre you have, it --
10 you -- some of these wells have cumulative production, in-
11 cluding wells that when we were operating for Mr. McHugh,
12 we produced way more oil in some of those wells than they
13 could have had under their own 320-acre parcel of land, and
14 so, yes, I think that's my biggest concern, that at the
15 higher rate you are going to drain other areas.

16 Q We see in other reservoirs, this isn't
17 unique, but it may be unique in the sense it can reach so
18 far, if there is that kind of communication within the re-
19 servoir within the major fracture system. We're trying to
20 visualize the performance of these super-wells.

21 A Well, I -- I'm not sure that all of the
22 Bear Canyon Unit owners would agree with me, but it's my
23 feeling that the initial pressure measured in the Bear
24 Canyon 1 and, although we don't have a map right now, but
25 the Bear Canyon 1 was probably 3 to 4 miles from the

1 nearest Gavilan well that had any basic ability to pro-
2 duce, and it's my feeling that even that far away we were
3 able to -- at that point in the reservoir had suffered some
4 pressure depletion.

5 Q Thank you, Mr. Roe.

6 MR. LEMAY: Yes, Mr. Kellahin?

7 MR. KELLAHIN: Mr. Chairman, I
8 have three quick areas of redirect.

9
10 REDIRECT EXAMINATION

11 BY MR. KELLAHIN:

12 Q When we look at the pressure measure-
13 ments taken in the unit, Mr. Roe, in any of these periods
14 of time, they are surface pressure measurements, are they
15 not?

16 A For the unit wells?

17 Q Yes, sir.

18 A Yes.

19 Q I want to examine with you and see of
20 there is an alternative engineering explanation that may
21 account for the appearance of a differential on Proponents
22 Exhibit Number Twenty.

23 Take, for example, what is the approxi-
24 mate range of depths of the wells in the unit itself?

25 A Okay. Now, Mr. Kellahin, you're talking

1 about the wells that are in the original pressure main-
2 tenance area.

3 Q In the main project area, yes, sir.

4 A Because the wells in the expansion area,
5 those were actual bomb measurements.

6 Q I see. I'm looking in the main project
7 area. Are those wells in the range of 5000 to 7000 feet
8 deep?

9 A They -- because of the dip in the reser-
10 voir they're much shallower and in order to extrapolate to
11 the datum that we have here you quite often have to extra-
12 polate the 700 to 800 feet and you're doing that below the
13 depth of the wellbore and that will put you actually to a
14 datum level that's below the base of the pay, and so what
15 you're doing is you're having to guess where the gas/oil
16 contact is and what the pressure gradient in the reservoir
17 is from the deepest point you can measure down to the datum
18 point, and so there is a very big uncertainty introduced if
19 you don't know where your gas/oil contact is.

20 Q And that uncertainty regardless of the
21 competency of the engineers making the calculation could
22 induce a range of variations in the numbers to account for
23 the difference?

24 A Yes. With the structural relief we have
25 in -- from the gas cap area to our datum, the datum we

1 chose was when we were studying Gavilan. We could well
2 have chosen a different datum pressure had we been looking
3 at the gas cap area, but we've got often the need to calcu-
4 late the hydrostatic head of 800 to 1000 feet with no know-
5 ledge of what that gradient would be other than our best
6 guess.

7 Now, again, that -- that applies only to
8 the pressures that we have from the gas cap area.

9 Q Mr. Roe, I'm going to show you what I
10 have marked for introduction as Dugan Exhibit Number
11 Eleven. Taking the tabulation of information from your
12 exhibits, Mr. Roe, and using Dr. Lee's display of what the
13 tank has in each of the five tanks for the original oil in
14 place --

15 A Yes, sir.

16 Q -- I want to use your information and
17 determine for me, first of all, what we have for an ori-
18 ginal oil in place value within the West Puerto Chiquito
19 Mancos Pool. If we use Dr. Lee's value for the tank on the
20 far right, we have 21.3-million barrels?

21 A Yes.

22 Q And if we add that to the next two, the
23 next tank, it's 29.8-million barrels?

24 A Yes, sir.

25 Q And then finally in the expansion area

1 if we add in the 19-million barrels in that tank?

2 A Yes.

3 Q Do we get a total oil in place using
4 that method of about 70.1-million barrels?

5 A Yes, we do.

6 Q Okay. When we go over to the Gavilan
7 side and take the two tanks in that side of Gavilan, we
8 have an original oil in place value for the eastern portion
9 of Gavilan of 17.1-million?

10 A Yes, sir.

11 Q And the western portion is 28.2-million?

12 A Yes.

13 Q All right. For comparisons, Mr. Roe,
14 let's take a point in time beginning with January of 1986
15 for a 2-year period ending with January of 1988. Subject
16 to check, Mr. Roe, would you follow through with me and if
17 during that period of time the entire western -- the West
18 Puerto Chiquito Mancos area within the unit has produced a
19 total volume of oil of 1.6249-million barrels of oil. Do
20 you see that in the summary?

21 A Yes, I do.

22 Q And if we look during that same period
23 of time and find what the total production is out of the
24 Gavilan area, it is 2.3425-million?

25 A Yes, that's correct.

1 Q Okay. To make the calculation to deter-
2 mine what the percentage of oil recovery in each area is to
3 the original oil in place, am I correct in taking as the
4 numerator for the unit side, including the expansion area,
5 taking the 1.6249 figure and as the denominator the 70.1-
6 million.

7 A Yes.

8 Q Do you have your little engineering cal-
9 culator?

10 A Yes, I do.

11 Q Okay, what's the percentage of recovery
12 in West Puerto Chiquito Mancos in that 2-year period?

13 A It would be 2.32 percent of oil in
14 place.

15 Q And that's what's indicated in the lower
16 right block when it says "COU"?

17 A Yes, sir.

18 Q And would you do the same thing in the
19 Gavilan area and take the original oil in place as the de-
20 nominator and the oil recovery as the numerator, and give
21 us the percentage of recovery during that same period of
22 time?

23 A That would be 5.7 -- 5.17 percent of the
24 oil in place.

25 Q Take a moment and find that Exhibit 22,

1 if you'll leave your calculator on, Mr. Roe, and if you'll
2 take Mr. Hueni's reservoir voidage and just assume it's
3 right, he's done it right, what does he show for reservoir
4 voidage during the lower or restricted rate period in Feb-
5 ruary '87 and June of '87, what is this number?

6 A Okay, during that period of time the re-
7 servoir was voided 8.35 reservoir barrels per stock tank
8 barrel.

9 Q Multiply that by the stock tank barrels
10 per psi pressure, and what do you get when you multiply
11 those two together?

12 A We end up with 265,000 -- I'm sorry,
13 26,520 barrels of oil.

14 Q 26,520 reservoir barrels produced in
15 this period per pound of loss of reservoir pressure, is
16 that what that is?

17 A That's what I wound up with, yes, sir.

18 Q Do the same for the normal rate period,
19 would you, please?

20 A That would be 35,595.

21 Q Rounding it off to 35,600 reservoir
22 barrels per pound of pressure loss during the normal rate
23 period from July of '87 to October, '87, that's what you
24 got?

25 A Yes, sir.

1 Q Would you do it for the last (unclear)?
2 What did you get?

3 A That would be 41,600 rounded off to the
4 nearest hundred.

5 Q You get 41,600 reservoir barrels at the
6 restricted rate per pound of loss of reservoir pressure.

7 A Yes, that's right.

8 Q Would you take the 41,600 and subtract
9 the 35,600? What did you get?

10 A 6000.

11 Q You get 6000 more reservoir barrels per
12 pound of pressure loss at the restricted rate than you do
13 at the normal rate.

14 A Based on those numbers, yes I would say
15 that that's what it indicates.

16 MR. KELLAHIN: Mr. Chairman,
17 we move the introduction of Dugan Exhibit Number Eleven.

18 MR. LEMAY: Exhibit included
19 without objection.

20 Additional questions?

21 MR. DOUGLASS: I have some.

22

23 RECROSS EXAMINATION

24 BY MR. DOUGLASS:

25 Q Mr. Roe, did you prepare Exhibit Eleven?

1 A Well, during the lunch hour I had pre-
2 pared the numbers that went into Exhibit Eleven but I did
3 not prepare Exhibit Eleven, no, sir.

4 Q Whose writing is this?

5 A I am going to anticipate that this is
6 Sun's engineer with which I have worked very closely
7 throughout this project.

8 Q Is the total production, let's see here,
9 put this map back up, is the total -- is this to compare
10 production from 1-86 through January of '88? Is that what
11 it attests to?

12 A Yes, sir.

13 Q All right, and in the unit where the
14 pressure maintenance is occurring, the total, do I see the
15 total oil in place originally was 50 -- is that 51.1?

16 A You're talking about just the pressure
17 maintenance area?

18 Q Yes.

19 A Yes, sir, that's correct.

20 Q And how much oil did it produce during
21 that period of time?

22 A Just the pressure maintenance area?

23 Q Yes. 4 and 5.

24 A I guess

25 Q It's on your exhibit there, isn't it,

1 244.4, isn't it?

2 A Yes, sir.

3 Q Okay, how much is the oil -- if the oil
4 in place is 51.1 barrel -- 50.1-million barrels of oil in
5 place, how much did the unit, pressure maintenance unit
6 present -- produce with this effective pressure maintenance
7 project over there during that period of time of this oil
8 in place?

9 A 0.5 percent, roughly.

10 Q 0.5 percent, so if the -- if this expan-
11 sion area here, if my figures were correct awhile ago, it
12 was pretty -- as I recall it was something around 8 percent
13 or so. Is that correct, it was producing (unclear).

14 A Well, when we calculated how much was
15 produced from the expansion area and assumed that it did
16 not -- was not included by the unit, yes, sir.

17 Q If the -- if the barrier is there as we
18 have indicated that it is, wouldn't producing a half of a
19 percent of the original oil in place from the pressure
20 maintenance area indicate that it's near the end of its
21 producing life?

22 A If the barrier is there, yes, that's
23 right.

24 MR. DOUGLASS: Pass the wit-
25 ness.

1 MR. LEMAY: Additional ques-
2 tions?

3 Mr. Chavez.

4 MR. CHAVEZ: Just one.

5
6 QUESTIONS BY MR. CHAVEZ

7 Q Mr. Roe, you interpreted the difference
8 between the pressures on the ends of your lines there on
9 your Exhibit Four as showing pressure support, is that
10 correct?

11 A Yes, sir.

12 Q Are you assuming that pressure support
13 is entirely from the pressure maintenance project?

14 A Well, no, not totally. One of the wells
15 in that group of wells has probably been getting some in-
16 flow from maybe areas to the north, but with the exception
17 of that one well maybe the rest of them would be from the
18 (unclear). I really have just started to think along those
19 lines of our communication with the area to the north and I
20 do know Amoco does not agree with that, so I can't state,
21 that, you know we are draining or communicating with the
22 unit, but I -- if we aren't, then the only other place for
23 that pressure support would be the pressure maintenance
24 project.

25 Q Did you hear Mr. Bush's testimony about

1 a bottom hole pressure approximately 900 and I forget what
2 psi in the Bear Canyon Unit No. 1 to the north?

3 A Yes, sir. That -- that actually occur-
4 red after the well had produced approximately 12,000 bar-
5 rels of oil. I do have the Bear Canon Unit wells plotted
6 on that graph.

7 Q Thank you.

8 MR. LEMAY; Additional ques-
9 tions?

10 MR. DOUGLASS: Let me ask Mr.
11 Roe just one question on the bottom hole pressure that we
12 talked about.

13

14 RE CROSS EXAMINATION

15 BY MR. DOUGLASS:

16 Q That you got some injection wells you
17 couldn't measure the pressure down in the -- and -- and you
18 had difficulty in measuring the pressure extrapolating it
19 below the injection wells?

20 A Yes, sir.

21 Q Were you aware that the pressures that
22 are shown on Exhibit Twenty out here, for instance, E-10,
23 L-27, C-34, were those injection well pressures in the
24 pressure maintenance unit?

25 A Yes, they are.

1 Q They are?

2 A Well, --

3 Q The E-10 is an injection well and the
4 C-34 is an injection well and the L-27 is an injection
5 well?

6 A Well, as I'm sure you're aware, those
7 wells, the E-10, we arrived at that pressure by using sur-
8 face pressure and calculate the bottom hole pressure, and
9 the L-27, we did have a bomb measurement but we still had
10 to extrapolate -- the bomb was, say, at a depth of about
11 6810, required us to extrapolate down about 300 feet to get
12 to our subsea datum below the depth of the well.

13 The K-13 --

14 Q Wait a minute now, I'm sorry, I asked
15 you about three wells. E-10, is that well in the gas cap?
16 Is it an injection well?

17 A Oh, no, I didn't mean to (not clearly
18 audible).

19 Q Were you aware that that's one of the
20 three pressures at the end of this pressures on Exhibit
21 Twenty?

22 A Well, yes, sir.

23 Q And the C-34, is that well an injection
24 well or in the gas cap now?

25 A It's not an injection well.

1 Q Is it in the gas cap? I honestly can't
2 tell you the location of the gas cap but I will say I don't
3 know anything about that pressure.

4 Q How about the L-27? Is it an injection
5 well?

6 A The L-27 is not an injection well but at
7 the last survey we did have a gas gradient in the wellbore,
8 which most of -- most of the wells in Gavilan did, and I
9 think my only point is we have to extrapolate, like the
10 L-27, we're measuring as deep as we can get with the bomb
11 is 5850, and I think our +370 datum is 6730, so we -- we
12 have roughly 900 feet that we have to guess at to get down
13 to our datum.

14 MR. DOUGLASS: Pass the wit-
15 ness.

16 MR. LEMAY: Additional ques-
17 tions?

18 MR. KELLAHIN: Nothing
19 further, Mr. Chairman. We pass the witness.

20 MR. LEMAY: Pardon?

21 MR. KELLAHIN: I have no fur-
22 ther questions.

23 MR. LEMAY: The witness may be
24 excused. Let's take a fifteen minute break.

25

1 (Thereupon a recess was taken.)

2
3 MR. LEMAY: Mr. Carr?

4 MR. CARR: May it please the
5 Commission, at this time we call Albert R. Greer.

6 I request that the record
7 reflect that Mr. Greer has previously testified in these
8 consolidated cases; that he has been qualified as an expert
9 witness in petroleum engineering; and that he's under oath.

10 MR. DOUGLASS: We have no
11 questions about his qualifications.

12 MR. LEMAY: His qualifications
13 are accepted.

14
15 ALBERT R. GREER,
16 being called as a witness and being duly sworn upon his
17 oath, testified as follows, to-wit:

18
19 DIRECT EXAMINATION

20 BY MR. CARR:

21 Q Mr. Greer, you were present when Mr.
22 Hueni presented Mallon -- or Gavilan Pool Exhibit Number
23 Twenty-one, which is another depiction taken from your
24 rainbow map, is that correct?

25 A Yes, sir.

1 Q And you were present when Mr. Hueni
2 discussed the pressure in the B-18 Well and suggested that
3 perhaps it was as high as it is as depicted because it was
4 taken shortly after there was injection in that well?

5 A Yes, sir.

6 Q Have you prepared an exhibit which shows
7 the actual pressure information for the B-18 in and around
8 the time indicated on this exhibit, being November 19,
9 1987?

10 A Yes, sir.

11 Q Is that contained in Benson-Montin-Greer
12 Exhibit Number Four?

13 A Yes, sir.

14 Q Would you please refer to that exhibit
15 and review the pressures that were actually measured in
16 that well at this particular time?

17 A Yes, sir. As I understand --

18 MR. PEARCE: Bill, may I ask,
19 what is that?

20 MR. CARR: This is Exhibit
21 Twenty-one, which is the modified version of the rainbow
22 map.

Perhaps it would be helpful to
23 advise the Commission that we have consolidated both
24 direct and rebuttal testimony. We're going to be working
25 back and forth and yours should be numbered (not clearly

1 understood).

2 MR. DOUGLASS: Is that Exhibit
3 Number Four?

4 MR. CARR: It's Exhibit Number
5 Four. It's entitled Surface Pressures C.O.U. B-18.

6 A Excuse me, there are some extra copies.

7 MR. CARR: We have some extra
8 copies if you need them.

9 MR. LUND: Thank you, sorry.

10 Q All right, Mr. Greer, would you now re-
11 fer to Exhibit Number Four?

12 A Yes, sir. It's my understanding that
13 Mr. Hueni adjusted the B-18 pressures down because he un-
14 derstood that the pressure in the B-18 was measured immedi-
15 ately after injection, but in addition the B-18 had shown
16 interference from the next nearest well to the west, the
17 K-13, and since it showed interference he assumed that the
18 pressures would be equalized.

19 But the fact of the matter is that this
20 is one of the areas that is really tight; in fact, it's the
21 tightest area in the -- in the project.

22 We've had a lot of discussion about the
23 tight area, in fact it's so tight it's a barrier, but
24 really the tightest area is up around the injection wells
25 and this particular well, the B-18, the pressure that we

1 measured on it was taken November 19th at the same time as
2 all the other pressures in the November pressure survey,
3 and the pressure was not taken immediately after -- after
4 injection but after a 3-day shut-in, the same as all the
5 other wells.

6 We have here a schedule of the activity
7 of that well for this part of the month of November and,
8 although I do not have any other dead weight test than the
9 one taken November 19th, we do have the chart, the meter
10 reading, we used to calculate volumes for the -- for this
11 well, so even though it was shut in, why, the meter chart
12 was left on the well and we could tell from the static
13 readings on the chart approximately what the pressure --
14 what the pressure is.

15 And we do that in the same fashion as as
16 one calculates by the gas volume, so even though gas is not
17 going through the meter, the meter nevertheless registers
18 the static pressure on the well, and I've shown these read-
19 ings and what the readings mean in terms of pressure, and
20 the first direct calculation results from a (not clearly
21 understood) pressure.

22 And we can see from this schedule the
23 highest pressure even while the well was injecting in the
24 early part of November was only about 1770, 60, maybe 70
25 pounds.

1 November 19th when the dead weight test
2 was taken it shows 1693 pounds. At the same time the meter
3 reading was only 1677 pounds; our meter was off by about 16
4 pounds. That's about one percent.

5 Then November 20th, 21st and 22nd, we
6 injected a small volume. and I can't tell what that was
7 for, but we could tell it was a pretty small volume because
8 the pressure, injection pressure, increased only to about
9 1713 pounds by the -- by the meter, and adding a 16 pound
10 correction we've got about 1730 pounds.

11 Then we shut it in on November 22nd and
12 it was kept shut-in for all the rest of the time and
13 shut-in pressures were taken for the length of that and we
14 can see there approximately how the pressures dropped off.

15 It looks like on November 26th we have
16 about the lowest reading and on November 27th, 28th it
17 shows a little higher reading.

18 Well, Mr. Chairman, I'm sure the pres-
19 sure was still dropping at that time and the reason it
20 shows a little higher pressure, I have an idea that that
21 was
22 pressure and November 27th, 28th, it shows a little higher
23 reading.

24 Mr. Chairman, I'm sure the pressure was still dropping at
25 that time and the reason it shows a little higher pressure,

1 I have an idea that that was probably a warmer day. These
2 meters are supposed to be temperature compensated but they
3 aren't quite and on cold days they'll read lower than they
4 do on warmer days.

5 I would judge from November 23rd to
6 November 28th, during that shut-in period, that the well's
7 pressure probably would drop at the rate of about 4 or 5
8 pounds a day.

9 But in any event, after five days shut-
10 in, first a three day shut-in, three days with low volume
11 injection, let's see, six days shut-in, the pressure, by
12 meter, showed about 1645 pounds, so the pressure in that
13 well at the time of the survey would be just about, to the
14 inside on the red triangle there, some 30 pounds less than
15 November 19th pressure, but that's about all, and that's
16 the steepest pressure gradient that we have anywhere in the
17 reservoir in that particular well, Mr Chairman. When it was
18 first drilled, it's our best injection well, when it was
19 first drilled and completed it made about -- about 5 bar-
20 rels of oil a day and about 10 MCF of gas. We knew it was
21 in the gas cap part of the reservoir in communication with
22 the rest of the reservoir, and we needed that well in that
23 acreage in the unit even though it was tight.

24 We knew that when we continued our
25 pressure maintenance project and pressured up that area, if

1 it were not in the unit that somebody else could perhaps
2 come along and drill and well and take gas out of the gas
3 cap and destroy our pressure maintenance project.

4 At that time the requirements for wells
5 in the participating area where they had to be commercially
6 productive. This well obviously was not commercially pro-
7 ductive, so our unit agreement was amended so that it now
8 reads that we can include in the participating area land
9 necessary for unit operations. It doesn't necessarily have
10 to be commercially productive, and because of that, we were
11 able to bring in land that we needed in the gas cap area,
12 even though it's commercially nonproductive. We needed it
13 to contain a gas cap.

14 So we had left a big pressure differen-
15 tial, the biggest in the field, about a mile and a half and
16 then 4-or-500 pounds, and yet that well injected like
17 6-billion cubic feet after the gas for a total injection of
18 20 years. There's no question that that gas has gone out
19 of the tight block into the reservoir, spread just as I in-
20 dicated in March, north/south and then it moves gradually
21 east to west; diffuses is the word that I think fits this
22 best. There's a real tight streak in between those wells.

23 Q Now, Mr. Greer, is what has been marked
24 as BMG Exhibit Number Five a graphic presentation of the
25 pressure information shown on Exhibit Number Four?

1 A Yes, sir. When this graph was prepared
2 I thought that we'd ended our testing on the 26th and
3 that's as far as those pressures go. There's two more
4 pressures on the schedule than shows on the graph, but
5 generally what you see is one more day off the edge of the
6 graph that the pressures would not drop down 400 pounds to
7 the point that is shown on Mallon Exhibit 21.

8 Q Mr. Greer, is it your testimony then
9 that the point on the B-18, the pressure point is as you
10 depicted in your rainbow map and it should not be lowered
11 as suggested by Mr. Hueni?

12 A Oh, yes.

13 Q Mr. Greer, we're heard a lot in this
14 hearing about how gas injection is not working and doesn't
15 work with gravity drainage. Are you aware of situations
16 where in fact it is?

17 A Yes, sir.

18 Q Would you refer to Benson-Montin-Greer
19 Exhibit Number Three (sic), identify this and point out the
20 relevant portions of this exhibit?

21 A Yes, Mr. Chairman. This is a paper on
22 the Bahrain field which I found very -- very interesting.
23 It has a transmissibility about like Canada Ojitos Unit.

24 Q Before we go on, that is marked Exhibit
25 Number Six, not Exhibit Number Three.

1 But what we wanted to show here is that
2 there are occasions in which gas injection and pressure
3 maintenance has been successful and what I found of parti-
4 cular interest is on the last page, Conclusions, Conclusion
5 Number 2, and it says, "Gravity drainage as well as the oil
6 wettability characteristics of the rock have been conducive
7 to a higher oil recovery by gas than by water."

8 And, actually, what happened in part of
9 this field, Mr Chairman, the natural water drive was
10 allowed to operate and oil recovered that way. Then they
11 introduced a gas injection, drove the water back down, and
12 found that they recovered additional oil in the area that
13 had been swept by water.

14 And it's just a higher efficiency of gas
15 injection and gravity drainage that permitted that, and I
16 think it's very interesting to know that at least some
17 places you have records of gas injection and gravity drain-
18 age working very effectively.

19 Q Mr. Greer, you were present for the
20 testimony of Mr. Elkins, were you not?

21 A Yes, sir.

22 Q And what was your reaction to that tes-
23 timony.

24 A I was, of course, delighted to see Mr.
25 Elkins. It's been forty years since we worked together on

1 engineering committees back in Oklahoma and -- and also
2 I'm delighted to see his analysis of interference tests
3 which I struggled to design and analyze myself some four
4 years ago, I'd like to point out the things that Mr. Elkins
5 has confirmed with respect to the way I've analyzed these
6 interference tests, particularly this one.

7 Q Perhaps we should go to the three exhi-
8 bits that are contained in Exhibit Seven and perhaps we
9 should start with Exhibit Seven-A.

10 A Well, I was first going to discuss some
11 of the things I agreed on first.

12 Q All right. Okay. Why don't we do that.

13 A This was real important to me, Mr.
14 Chairman. I have the highest regard for Mr. Elkins and
15 he's an expert in his field, not only in regards to reser-
16 voir engineering but particularly interference testing and
17 analysis of (unclear.)

18 The first thing I note is that he used
19 the EI formula, the same as I did, which, by the way, Ber-
20 geson has said in these hearings it did not apply. I don't
21 know what Bergeson's current position is but that's what
22 it's been in the past.

23 He used under saturated oil, particular-
24 ly compressibility under saturated oil, which is what I
25 used. Bergeson's observation is that it's saturated, and

1 that makes a tremendous difference in the calculations.
2 Saturated oil has a compressibility like 10^3 20 times under
3 saturated oil depending on the pressures, and so at figures
4 for compressibility of oil (not clearly understood.)

5 Now, for total system compressibility,
6 when I made my study 20 years ago there just was not infor-
7 mation of the kind that one would like to have with respect
8 to the compressibility of the rock and I realize that it
9 probably, you know, you have an intuition when you're
10 thinking about a fractured shale, that it's going to have
11 a higher compressibility than anything else, so at that
12 time I -- I used a spread, a high and a low, in making my
13 calculations and we use some different values for the
14 saturation of the reservoir in terms of water and oil and
15 such as that. Overall Mr. Elkins used a compressibility,
16 if my notes are right, he used a (unclear) of 37.5 times
17 10^{-6} .

18 Now, for my low calculation, by low I
19 mean low compressibility which gives high -- high volume of
20 oil in place, I used 25. And for my high side I used 50,
21 and I calculated the results both ways, my high and low,
22 and I decided at that time the only thing I could do about
23 it was probably the best guess or estimate would be halfway
24 between; halfway would be 37.5×10^{-6} .

25 Mr. Elkins used 35.8. It is heartening

1 to see someone as experienced as Mr. Elkins agree with me
2 in that total.

3 Now, he also -- we also agree that --
4 now this was about a 30-day test, and we shut all wells in
5 the field in and (unclear) 60 days and then conducted the
6 test and -- and he agrees with my analysis that the test
7 results show all the oil in place, not just oil in frac-
8 tures, but oil -- he perhaps thinks of the -- as far as the
9 storage, is the thickest porosity. I'm not real sure about
10 that. I understood that he's thinking about the fine frac-
11 tures, as well as that.

12 My feeling is that it's all fractured
13 porosity, the high capacity system, the tight blocks and
14 the tight blocks are primarily fractures, too, tight frac-
15 tures.

16 But now he made his analysis that all of
17 the oil that's represented by this test, based on compres-
18 sibility of the block and his perception especially of the
19 fractures.

20 I made my analysis based on his exhibit
21 of the system and the size of the blocks which I have esti-
22 mated.

23 So we agree on that. So it is hearten-
24 ing to see his close agreement.

25 Q Are there other areas of agreement?

1 A Yes, sir. His final calculation of
2 transmissibility, he gets about the same thing as I did but
3 he got about 2-1/2 times as much oil in place as I did and
4 the reason for that is that Mr. Elkins, not being as
5 familiar with the project as I, selected the wrong well for
6 his well pair and, of course, in a way it's unfortunate
7 we're in this hearing process. I know that if it -- had it
8 not been for the hearing process, Mr. Elkins in studying
9 this reservoir, when he came to this point he would have
10 called and asked me, why in the world did you use the L-11
11 Well instead of the P-11. Clearly from a cursory examina-
12 tion of this test, one would say that the P-11 Well would
13 be the proper one to use, and that was my thought when we
14 started the test and that's why I selected it as the first
15 well.

16 But what happened, then, and we put the
17 wells on in series, produced one well for a few days and
18 then we added another well and then later on we added an-
19 other well. And to explain why the P-11 Well was not the
20 proper candidate in this test, we need to look at Exhibit
21 Seven-A.

22 Q All right, we'll do that now. Before we
23 do that, Mr. Greer, is this the only point on which you ac-
24 tually disagree with Mr. Elkins?

25 A As I gathered from his explanation of

1 his analysis of the interference test, that's the only
2 thing I could see as an area of disagreement.

3 Q All right. Would you go to Exhibit
4 Seven-A, please, and indicate what each of these graphs
5 show?

6 A Yes, sir. Mr. Chairman, this graph
7 shows how the pressure would drop at various distances
8 from the well which we put on production. You can see
9 there at the top of the graph at a distance of about 5
10 miles that no interference would show up there for several
11 days.

12 At 8000 feet it begins to show up in
13 about one day, two days.

14 At 4000 foot radius it shows in about
15 two hours; 2000 foot radius quicker than that.

16 And, you know, Mr. Chairman, that by
17 about the seventh or eighth day the pressures were dropping
18 at the 8000 foot radius, the 4000 foot radius, and the 2000
19 foot radius, at almost the same rate, not quite, but almost
20 the same rate.

21 We get out to 30 days and the dashed
22 line, and looking at the upper graph of this display, Plate
23 I, from that time on the radius of drainage in the sense
24 that it reached the field boundary, and the boundary in
25 this instance, which we'll look at a little bit later, is

1 in the edge of reservoir or the beginning of tighter,
2 tighter formations.

3 At that time, about 31 days, from that
4 point forward, then, the reservoir throughout that area, is
5 in what we sometimes refer to as a pseudo steady state de-
6 cline, or a steady state decline. All throughout the re-
7 servoir the pressures will be dropping at the same rate, 5
8 miles away, 1 mile away, and even in the wellbore, the
9 pressures will be dropping at the same rate. This is one
10 of the things that makes the use of interference wells most
11 helpful in analyzing the pressure decline in a reservoir
12 and why -- you'll see later on why I like to use pressure
13 differences rather than try to work with absolute pres-
14 sures.

15 Now, the thing that happened when we
16 started this test, the P-11 was within, oh, I forget now,
17 maybe a couple hundred feet structurally; now, please
18 remember, Mr. Chairman, this part of the reservoir is where
19 it's fairly steep and dipping, I believe it's 4-or-500 feet
20 and, oh, it's a half a mile or more away from -- from the
21 P-11. The oil in a sense encounters the bubble point as --
22 see this oil was under saturated and producing. In a sense
23 you could call that bubble point pressure down -- down dip.
24 It's around 1520 pounds of the temperature in this area;
25 the wells have a bubble point at about 1570-or-80 at Gavi-

1 lan temperature, but this temperature is around 1520, as I
2 recall, and what happened when we put that P-11 on produc-
3 tion, it pulled the pressure out of the wellbore down be-
4 low the bubble point and when it did, then there was an
5 area of saturated oil and a higher compressibility, and, of
6 course, I didn't realize all this until after we got all
7 the information together, but I spent a lot of time in
8 designing this test and trying to figure out the things
9 that I needed to know to be certain that I had a valid
10 test, and, of course, among other things, we got approval
11 of the Conservation Commission to conduct the test and
12 transfer allowables, and such as that, and I realized that
13 one of the things that I needed to look for in this -- this
14 reservoir that was so strange, I had low permeability and
15 those blocks that acted like little individual reservoirs,
16 and yet if you have (not clearly understood) a pressure
17 build-up it will just flatten off rapidly, sometimes in
18 just a few hours.

19 That told us that we were dealing with a
20 small reservoir.

21 When we turned around and produced the
22 well, the operating bottom hole pressure would do the same
23 thing, it would level off right quick, so we knew then that
24 even if it was a small reservoir, it was not a closed re-
25 servoir. In a closed reservoir, just a few acres, why in

1 just a matter of hours, if not days, why it would be de-
2 pleted, but instead it would just continue in depth; the
3 pressure, the operating pressure didn't drop. It would
4 just sit there like it was just pumping oil out of a tank.
5 So we had this -- this strange situation and because of
6 that and such a variation, apparent variation, I didn't
7 know what it was until I ran this test, but apparent vari-
8 ation that we watched as we depleted wells and watched the
9 pressures. I felt like I needed to have one really posi-
10 tive check that this test was a valid test and that posi-
11 tive check would be that the pressure in the operating well
12 would drop at the same rate as all the rest of the reser-
13 voir.

14 Well, I got to analyzing and testing to
15 determine that, Mr. Chairman. At that time we were pro-
16 ducing these wells with subsurface hydraulic pumps and in
17 order to control the situation, knowing just what we were
18 doing, we would close in the casing and pump all the oil
19 and gas up the production tubing and that way we created a
20 gas blanket from the surface to the pump and then by taking
21 dead weight pressures from the surface, we could tell, even
22 though we couldn't tell the absolute pressure, exactly, be-
23 cause we would have to estimate that weighted column of gas
24 we could tell very closely the difference in pressures and
25 this we did and we found that when we put the (unclear) on

1 and studied its operating history, its operating bottom
2 hole pressure wandered -- wandered down, it didn't do like
3 the rest of the observation wells, and then when I got to
4 studying a few more details, and I realized we'd pulled
5 the pressure down below the bubble point and we had an are
6 of saturated oil by this well, which then, although it
7 seemed to be small compared to the overall reservoir, it
8 would not affect the overall calculation for a different --
9 for different producing well; it would give high readings,
10 high in a sense of the calculated oil in place.

11 So when we put the next well on, the
12 L-11, then it was a little more difficult and a little more
13 subjective as to how we calculated the effect of putting
14 the well on on the pressure, but that well produced like it
15 should. It's pressure dropped down and it leveled off and
16 it had a good test.

17 So I analyzed the L-11. I feel that if
18 Mr. Elkins had analyzed L-11, we would have even gotten
19 closer figures.

20 I think it might be interesting to the
21 Commission to take a look at some of the details of this
22 test on a graph.

23 Q And that's what's marked as Exhibit
24 Number Seven?

25 A Yes, sir.

1 Q And that's the long --

2 A Yes.

3 Q -- it's the long graph.

4 All right, sir, will you refer to that?

5 A I'm sorry I don't have a larger display
6 of this but I'd like to point out a couple of things.

7 The little squares show Phase I, Phase
8 II, Phase III and Phase IV, show which wells were shut-in
9 and which wells were producing during the test.

10 Now, at this time we did not have the
11 sensitive pressure gauges that are available now, so in
12 order to get a real accurate rate we had to do it with
13 fluid levels and we measured these fluid levels with
14 (unclear) and we would occasionally check the bottom hole
15 pressure to make certain that the density of the long hole
16 had not changed capacity, and we see that on the bottom
17 scale that prior to shutting wells in, we're producing, oh,
18 like 1000 to 1500 - 1200 barrels a day, and in April we
19 shut-in, I believe, the A-14 and as you see, the fluid
20 levels. started measuring them, and they began to build up
21 and then fell off again while producing.

22 Then the first week in June we shut the
23 rest of the wells in and you can see how the fluid levels
24 there build-up in the observation well until about the 24th
25 of July, in order to establish the gas blanket in the P-11

1 we produced it for two days and you can see, the response
2 in the observation wells when we did that.

3 Then, about August the 3rd, we put the
4 P-11 on permanent production, and you can see those little
5 square flags up there at the top of the graph, we felt this
6 test would be so interesting and just so hard to believe
7 the interference in this well in this reservoir, that we
8 asked representatives of the Oil Conservation Commission
9 and the United States Geological Survey, at that time the
10 Department of Interior's representative, to witness these
11 tests. Where you see those little flags is where we had
12 witnesses.

13 Now, we produced the P-11 with the L-11
14 as one of the observation wells until about the first of
15 September, and then put the L-11 on and then we can see in
16 September the steepening of the decline of the fluid levels
17 in the A-14 and also in the A-23.

18 Now those curves are not following ex-
19 actly the kinds of curves that we calculated on the graphs
20 we looked at just earlier, but in general, they very well
21 confirm what one would estimate.

22 Then, when I made my calculations, Mr.
23 Chairman, on the consequences of putting the L-11 on pro-
24 duction. I noted earlier, it's a little harder and more
25 subjective in terms of just what the response was, but at

1 least we had a valid well to work with.

2 And so I came up, then, from my calcu-
3 lation of about 6 or 8 darcy feet for transmissibility and
4 then around, taking the average, somewhere around 16 - 1700
5 barrels an acre of oil in place. And I think from the talk
6 then and the work I've done since then, I'm convinced that
7 was a really -- really a good test, very representative; I
8 mean we didn't have the problems then that we have now in
9 some of these other wells in that you have only a C zone
10 open in these wells so we just have one zone to be concern-
11 ed with. Also the oil is under saturated. The wells pro-
12 duce by solution gas/oil ratios, and so at that time we
13 just had a really ideal situation to make an interference
14 test.

15 Q Now, Mr. Greer, can we learn something
16 from this information concerning dual porosity and poten-
17 tial migration across the alleged barrier?

18 A I think so, Mr. Chairman, and I'd like
19 to at least --

20 Q Is that information contained on Exhibit
21 Seven-B?

22 A I'd like to refer still to Exhibit Seven
23 and I'd like to share with you my analysis and my assess-
24 ment of the drainage situation and by happenstance in the
25 way I feel that gives us insight as to whether or not

1 there's dual porosity in this in West Puerto Chiquito. I
2 don't know about Gavilan but I suspect they're going to be
3 about the same, but at least for West Puerto Chiquito we
4 have what I think is a pretty good country boy type analy-
5 sis and one I'd like to explain to you.

6 We can see at the end of 60 days of
7 shut-in that the pressure is still building in these wells.
8 Now that's -- that's kind of a contradiction to the high
9 transmissibility that we calculate, and so that could be
10 only two things in my view.

11 One, it could be dual porosity or it
12 could be migration from a tighter area. Obviously, I was
13 concerned at that time about it. I, my personal feeling
14 then, was that I just didn't know. I guess, like everyone,
15 you can hope for the best, maybe it really is dual porosity
16 and there's more oil there to get out.

17 The other calculations that I've made.
18 and, of course, it's a very difficult thing to analyze,
19 that I have concluded that about half of the total volume
20 was in the high capacity fractures. The other would be in
21 the tighter blocks. Again I felt like probably fractured,
22 a little tighter. So here we have a system of high trans-
23 missibility. I feel like we've measured all the oil in our
24 test and yet here the blame things are, the pressure is
25 still coming up.

1 So we assume it's one of those two
2 things, and we had no further information on that until
3 Gavilan was drilled, and, sure enough, there's Gavilan with
4 its lower pressures, and I wonder if we might take a look
5 at John Roe's Exhibit Four?

6 When the first well was drilled in Gavi-
7 lan and additional wells drilled, and we project the 11,000
8 barrels (unclear) decline rate back to zero production, on
9 this graph here we've shown around 1750 pounds, and we felt
10 or I felt, that the other pressures that we had, some of
11 them higher than that; that trend of mine, of course, is
12 kind of an average, not the maximum, however, the virgin
13 pressure in this area at that time should have been right
14 at 1900 pounds at this datum. It appeared to me, and I so
15 indicated in the 1983 hearing that there had probably been
16 some migration from Gavilan area into the unit on the order
17 of 80 to maybe 100 pounds, and then if we look at the graph
18 and see what those 80 to 100 pounds mean on the cumulative
19 production, we come up with something in the range of
20 700,000 barrels.

21 So we make just a rough estimate that it
22 looks like we've had 700,000 barrels of migration into the
23 unit.

24 We'll take a look in just a minute at
25 how -- what that translates into, migration, but I'd like

1 to, while we're talking about dual porosity and migration
2 together, the next -- the next thing that gave us a clue
3 about dual porosity or migration was in the fall of --
4 September of 1986. At that time the pressures began to
5 draw closer together. We had a pressure somewhere about
6 14-1500 pounds in the unit; Gavilan had somewhere around
7 14-1500 pounds, and when we shut wells in then, high capa-
8 city wells, they built up in two or three days, leveled off
9 and there was no pressure increase.

10 So why, when we have a -- when there's a
11 lower pressure, much lower than what we have in the inter-
12 ference test in 1965, greater pressure differential and
13 conversion, if there is oil trapped in a matrix with the
14 differential pressure higher now than it was then, why, why
15 don't we get a glimpse of relative pressure buildup in one
16 of them? We did not.

17 Now, that then lead me to believe that,
18 well, it is migration and it is not dual porosity.

19 Then a year later when we ran the Novem-
20 ber pressures, these same wells, and I'm referring now to
21 B-29, B-32, high capacity wells, when we shut them in,
22 their pressure built up.

23 Lower pressure, greater differential and
24 conversion, and now their pressure is built up and the only
25 difference is that there is a differential pressure across

1 tight spots and we've got migration from the unit building
2 the pressure up, so -- so I viewed that as migration and
3 not as dual porosity. That perhaps doesn't mean that there
4 is no dual porosity anywhere but my assessment of it is
5 that that's a pretty good indication that we don't have
6 enough to talk about in West Puerto Chiquito.

7 Q Are you ready now to go to Exhibit
8 Seven-B?

9 A Yes, sir.

10 Q Will you identify that?

11 A Yes, sir. This is the same formula that
12 (not clearly understood) there's a pressure difference over
13 20 years of about zero pounds to 300 pounds and I've used
14 150 as an average. I don't know, 200, 250, using that, we
15 come up with a transmissibility in that area, depending
16 upon the flow system, whether the distance along parallel
17 to the flow is greater than the width. Like, for instance,
18 if it's just as far east/west as it is north/south across
19 this tight streak, then the ratio of the length to the
20 width would be one and it would be about .5 darcy feet
21 would be the transmissibility.

22 And now, without going into any elabo-
23 rate calculation as to what does that mean in today's
24 world, we can look at a couple of things.

25 My analysis there shows, oh, about 100

1 barrels a day across the (unclear) and I've got three times
2 as much pressure differential now than before and that
3 would be 300, and of course I could have a mistake in these
4 calculations. I worked them up pretty fast and I have not
5 reviewed, but I have an idea there'll be some checks made
6 on them and we'll find out about it if there are.

7 The key, the key thing now, Mr. Chair-
8 man, the thing that our opposition worries about, that I
9 worry about in the opposite direction, our opposition is
10 afraid that there's not much gas moving across the tight
11 streak. I worry that there may be too much.

12 What happens, Mr. Chairman, when oil was
13 migrating from Gavilan to the Canada Ojitos Unit, the oil
14 was under saturated most of the time. Part of the time --
15 well, as a matter of fact all the time it was going that
16 direction, and so we're dealing strictly with oil through
17 that system.

18 Now then coming back the other way, when
19 gas gets mixed up with it, and more gas is mixed up with it
20 because the gas/oil ratio in the A and B zones have picked
21 up, we don't know just how the A and B zone are tied to-
22 gether with the C zone, but the pressures are obviously
23 equalized. When we take a barrel of oil going through a
24 reservoir, replace it with a barrel of gas, then the mobi-
25 lity increases tremendously and we only need a 10 or 20

1 point increase to take the -- even the .1 darcy feet, to 2
2 or more darcy feet, chances are that mobility is even more
3 than that.

4 So if, if, Mr. Chairman, the migration
5 that might exist is this way, then there is adequate trans-
6 missibility across that tight streak with the pressure
7 differential to support the production in the expansion
8 area.

9 Q Mr. Greer, Exhibit Seven-B is therefore
10 evidence of migration, not dual porosity.

11 A That's my assessment.

12 MR. CARR: May it please the
13 Commission, we appreciated the comment yesterday about how
14 you have one expert running one direction and another one
15 going exactly the opposite. We're going to try with two
16 exhibits now to explain some of those differences to you.

17 Q Mr. Greer, were you here for the testi-
18 mony of Dr. Charles Kohlhaas?

19 A Yes, sir.

20 Q And, let's see, we need Exhibit Forty-
21 one. Have you reviewed Dr. Kohlhaas' Exhibit Number Forty-
22 one in which he showed frac treatment responses in certain
23 wells and then examples where there was no frac treatment
24 response?

25 A Yes, sir, I have.

1 Q Do you concur in this information?

2 A I concur in part of what Mr. Kohlhaas
3 said. He said that if there is a response to a frac treat-
4 ment in a well, that there will be a pulse move through the
5 reservoir and it can be seen on a coordinate scale and he
6 gave as an example one of the wells in which the pressure
7 rises dramatically and then falls back down.

8 Then he went to another well and we'll
9 pick out the one, I think it's the second panel from the
10 top.

11 Q Between the C-34 and the B-32?

12 A Yes, sir.

13 Q Do you concur with that depiction of
14 what happened?

15 A Well, there he said that he used the
16 same scale as he did on the other one that showed a
17 response and here he sees no response, and he says that
18 that means there is -- there is no response to the frac
19 treatment.

20 Now, part of what Mr. Kohlhaas said is
21 true in that the pressure pulse, as it moves through the
22 reservoir will rise up at any point in the reservoir and
23 then come back down.

24 What's not correct is that for the dis-
25 tance shown between the C-34 and B-32, is that you can see

1 it on a coordinate graph at that scale, and we'll explain
2 why that is.

3 Q Are you ready to go to Exhibit Eight?

4 A Yes, sir.

5 Q Initially, Mr. Greer, would you just
6 explain to the Commission what Exhibit Eight is designed to
7 show?

8 A Yes, sir, it shows what pressure re-
9 sponses would be at different distances from -- from a well
10 that's been given a frac treatment. It shows how the pres-
11 sure would rise up and fall off, and the time this -- these
12 events take place, if the characteristics of the reservoir
13 are somewhat like that that we have found with our testing,
14 in this example, and it very closely fits the N-31, E-6
15 tract where there was about a 6 pound pressure pulse obser-
16 ved in that well, oh, approximately 3000 feet, I believe it
17 was, away from the -- the well that was being treated.

18 Now what happens as we go a little far-
19 ther away? The amplitude of that pressure response dies
20 out, falls off, and the -- these curves appear to change.
21 They appear to have a different character, but that, Mr.
22 Chairman, is just because of your perception of the curves.
23 They all do the same thing mathematically. They go up and
24 then come back down.

25 Now, the 10,000 foot distance is not

1 quite coming down yet.

2 Q Now that's the bottom line on the graph?

3 A That's the bottom line. That's about
4 how far apart the C-34 and the B-32 were. So despite what
5 Mr. Kohlhaas said, we would not expect to see a pressure
6 pulse or a bump out at that distance.

7 Q Now, Mr. Greer, yesterday I asked Dr.
8 Kohlhaas if he was aware of a rule of thumb as to what
9 would happen in a common -- where all reservoir character-
10 istics were the same, and you have wells, say, twice as far
11 apart as the original test, what would actually happen and
12 was there any kind of rule of thumb.

13 Does this exhibit show you how you could
14 estimate that?

15 A Yes, I gathered from Mr. Kohlhaas'
16 (unclear) that he didn't know whether there is a rule of
17 thumb or a direct relation, but there is, Mr. Chairman, a
18 direct relation, and we'll point that out.

19 Take the first well, the 3000-foot one,
20 and if you'll point it out --

21 Q This is the top line on the graph.

22 A There is a pulse there at the red arrow
23 which is about 6 pounds.

24 Now, if we move the observation well
25 twice as far away, what happens? The response, or the am-

1 plitude of the pressure response drops by a fourth; twice
2 as far away, a fourth of the pressure, and we look at that
3 and sure enough, it's a fourth of the pressure.

4 Now, not only that it's a fourth of the
5 pressure, the peak response comes at four times the first
6 well. The first well shows a response, a peak response,
7 about half a day; the well twice as far away shows it in
8 four days.

9 Now, the same thing applies as we go on
10 a little farther out, and despite the fact that those
11 curves appear to have different characters, they're all
12 really the same in a mathematical sense, and that -- that
13 relation exists all the way through. Now in my discussing
14 this with Professor Braden (unclear) at Stanford University
15 he pointed out that in view of that relation, that we might
16 find it useful and convenient to prepare a type curve, and
17 that we could prepare, really, one type curve and use it to
18 replace all these and deal with dimensional time and dimen-
19 sional pressure.

20 So, so now that we know what to look
21 for, that Mr. Kohlhaas couldn't a pressure response in the
22 B-32 and C-34 frac, because he didn't use the proper
23 technique to look for it.

24 So now we'll present how to look for it.

25 Q That's what's been marked Exhibit

1 Eight-A.

2 All right, Mr. Greer, would you identi-
3 fy Exhibit Eight-A for the Commission, please?

4 A Yes, sir. This is a copy of one of the
5 exhibits, of one of the pressure build ups that we've shown
6 in one of our exhibits at the March hearing, and it shows
7 the pressure response in the B-32 Well when the C-34 was
8 fraced, the response to the fracture.

9 What -- the way Mr. Kohlhaas analyzed
10 it, was first he said this well had no response to this
11 frac- ture treatment, and to any pressure build up, and of
12 course (not clearly understood). But then he made a Horner
13 log plot, (unclear) and all kinds of (unclear) since. He
14 said, well, there really is a response, although earlier
15 he'd said there's no response, he said, well, there's
16 nothing down there to respond to. But this response is
17 caused by a gravity effect which is sometimes defined as a
18 barrier or a boundary to the reservoir, and I disagree with
19 Mr. Kohlhaas' analysis there. He pointed that out, and
20 said, well, at Gavilan, when you have a boundary that shows
21 up in a build-up test, that even though the slope -- the
22 slope should be 2-to-1. What happens if you have a bound-
23 ary, Mr. Chairman, the pressure behaves somewhat different-
24 ly, obviously, than if it had been spread throughout a
25 a large area. Here, if there's a restriction some-

1 where, then the shape of pressure in time is different, and
2 the way it's different, if there's a boundary or a barrier,
3 you get a 2-to-1 increase in slope, and I pointed out in
4 that connection in one of the tests that we ran, not this
5 one, but here's a 2-to-1 slope and perhaps there would be a
6 boundary and I couldn't tell a difference in analyzing it,
7 was it happenstance or why did it occur within just a few
8 hours of the time of the frac job.

9 Here, the steepest slope that you can
10 get, right through there, is about 1.3 times the other
11 slope; not 2-to-1, Mr. Chairman, only 1.3.

12 So that's the first thing, the first
13 clue that we get, that really, that's not a boundary. If it
14 is a boundary, it's a fuzzy boundary; it's not a sharp
15 boundary. You might, perhaps in that area you might have a
16 slight change in permeability value, something like that,
17 but then there are a couple other things.

18 Q Now, how does this -- what's the signi-
19 ficance of this line on this graph?

20 A Well, that is, of course, the most signi-
21 ficant thing. See, Mr. Chairman, we had run a build-up
22 test on that well about 60 days before the frac treatment.
23 I don't even remember why we did it, but it's just one of
24 the routine tests that we take from time to time, and you
25 can see there is no change in the slope of that lower green

1 line graph, which, incidentally, on Mallon's exhibit they
2 had taken note of that part of the graph for some of their
3 markings and perhaps they didn't realize how important it
4 is to me to have that data.

5 But we see real clearly that there's no
6 change in the slope of that green line.

7 Now, if there were a barrier, a geologic
8 feature underground, it's not going to change in 60 days;
9 if it was there -- if there was a barrier there in April,
10 it should have been there in January, and it's not there.

11 Then the third thing, Mr. Chairman, the
12 intersection of the shaded area, that line right there with
13 the beginning slope, I calculate to be about 3 hours from
14 the time we start the frac treatment.

15 Now, what a coincidence, Mr. Chairman,
16 that this well has been shut in for three days, we don't
17 know when we're going to do the frac job, we plan it for
18 one day, and we hope that we can get the frac job off when
19 we schedule it, but we don't really know that until we do,
20 and what a coincidence that with all these factors, that we
21 go out and frac the well and in three hours there's a re-
22 sponse because of a boundary underground. What a coinci-
23 dence.

24 So we have those three things to tell
25 me, Mr. Chairman, that's not a boundary; that's the

1 response to our frac treatment.

2 Q Now, Mr. Greer, utilizing his graphs,
3 Dr. Kohlhaas removed a number of red lines which indicated
4 interference tests between the expansion area and the pres-
5 sure maintenance area in Canada Ojitos.

6 Do you think those red lines should have
7 been removed?

8 A No, sir, they ought to be put back on.

9 MR. CARR: Could we have Mal-
10 lon Exhibit Twenty-six?

11 Q Mr. Greer, we've heard a fair amount of
12 testimony in this case about the recovery efficiency of
13 various pools in this area.

14 I'd like to refer you to what has been
15 marked as Mallon Exhibit Twenty-six and ask you if in your
16 opinion are the pools depicted on this exhibit appropriate
17 pools for making this comparison?

18 A Well, I believe there's a lot of simi-
19 larity in Boulder Mancos, La Plata, East Puerto Chiquito,
20 Verde (sic) Gallup, and West Puerto Chiquito. Otero Gallup
21 I think probably needs to be excluded in that we have re-
22 ports of two sand lenses in that pool, 6 percent porosity
23 in the sand, and I think it's -- should not be compared.

24 I think a valid comparison is with
25 Boulder, East Puerto Chiquito, both being high in amounts

1 of gravity drainage, and Verde Gallup has got a lot of
2 gravity drainage, and the reason we're making this compar-
3 ison, Mr. Chairman, we need to understand the reservoir
4 characteristics and conditions under which these pools were
5 produced.

6 East Puerto Chiquito is operated by our
7 company. We operate it just as we do Canada Ojitos, to try
8 to get the maximum benefit of gravity drainage. We've not
9 yet started our gas injection and active waterflood. We
10 think there's some Basement oil we might pick up with water
11 there.

12 But the way we produced that pool, was
13 with the gas/oil ratios, because of the solution gas/oil
14 ratios in up structure wells, we shut them in and just pro-
15 duce the down dip wells to recover the oil by gravity
16 drainage.

17 So we've got a high recovery in East
18 Puerto Chiquito.

19 I'd like to look at some of the gravity
20 drainage aspects, particularly with respect to oil wells so
21 we can understand really what the issues are in trying to
22 get maximum recovery from this -- this very unusual reser-
23 voir.

24 Q Now, Mr. Greer, is your comparison of
25 Boulder and West Puerto Chiquito contained in what's been

1 marked as our Exhibit Number Three?

2 A Yes, sir.

3 Q Initially, I think it would helpful to
4 start by --

5 MR. DOUGLASS: Did you say
6 Exhibit Number Three?

7 MR. CARR: Three, which is the
8 black book.

9 Q If you will go to Exhibit Number Three,
10 and I think initially we ought to start by just explaining
11 what you really mean by gravity drainage, so we're all to-
12 gether to start with.

13 A All right. Mr. Chairman, I think if we
14 looked at --

15 MR. CARR: Just a second.
16 Exhibit Three is the black book. This is Exhibit Number
17 Three.

18 Q All right, Mr. Greer.

19 A Mr. Chairman, I'd just like to take the
20 time of the Commission to read something about gravity
21 drainage. It's just succinctly summarized by Frick, and
22 you can see the reference there, in the two paragraphs as
23 follows:

24 Q And you're on the gray pages that are
25 the first pages in Exhibit Three.

1 A Yes, sir.

2 "Gravity drainage is the self-propulsion
3 of oil downward in the reservoir rock. Under favorable
4 conditions is has been found to effect recoveries of 60 per
5 cent of the oil in place, which is comparable with or ex-
6 ceeding the recoveries normally obtained by water drive.
7 Gravity is an ever-present force in oil fields that will
8 drain oil from reservoir rock from higher to lower levels
9 wherever it is not overcome by encroaching edge water or
10 expanding gas.

11 Gravity drainage will be most effective
12 if a reservoir is produced under conditions which allow
13 flow of oil only or counterflow of oil and gas."

14 Now, to achieve these conditions, "flow
15 of oil only or counterflow of oil and gas", these are the
16 two things that are important.

17 "1. This may be attained under pressure
18 maintenance by crestal-gas injection, which keeps the gas
19 in solution, or

20 2. It may be attained by a gradual re-
21 duction in pressure, so that the oil and gas can segregate
22 continuously by counterflow.

23 3. It may also be obtained by first
24 producing the reservoir [rock] under a depletion-type
25 mechanism until the gas has been practically exhausted,

1 then by gravity drainage."

2 Then he says, "A thorough discussion of
3 the many aspects of gravity drainage will be found in the
4 classic paper by Lewis." And we have supplied the numbers
5 and the emphasis.

6 In our situation we don't have all three
7 choices. We only have two, because as I point out in my
8 next to last paragraph, in this formation once the oil is
9 produced by solution gas drive, then there is not going to
10 be enough oil and permeability, transmissibility left, to
11 affect gravity drainage under any kind of conditions other
12 than might be one or two barrels a day.

13 So we're limited to Items 1 and 2, pres-
14 sure maintenance or gradual reduction of pressure.

15 Now I've analyzed Boulder as to -- you
16 see, Boulder, Boulder was drilled at an opportune time. It
17 was drilled at the time that we still had proration in New
18 Mexico and the wells were restricted in production such
19 that they couldn't produce at excessive rates, and they had
20 capability, Mr. Chairman, for producing. They had high
21 transmissibility wells.

22 One of the wells drilled by Mobil got
23 out a control when they were drilling. I think they're
24 drilling wet, and it actually flowed some 4000 barrels a
25 day (unclear) till they got it under control. So we know

1 that it's high, high transmissibility, and so we know that
2 Boulder's got lots of (unclear.)

3 Now, another thing about Boulder, it's
4 about four miles long and a mile wide; four miles along the
5 strike and a mile down dip; ideal situation; short distance
6 down dip to drain and it's a steep dip. So then we put all
7 those things together and we calculated why the convention-
8 al Buckley-Leverett equation and with the gravity drainage
9 factor added and those calculations are shown, first, as we
10 pass the blue pages we might take a look at an interesting
11 feature in the pool. The structure is shown on the lower
12 blue sheet. The upper graph shows the pressure production
13 history up through 1966. At this time 75 percent, or so,
14 of the oil had been recovered.

15 We show there some of the pressures that
16 were taken. Now Boulder initially had under saturated oil
17 and a gas cap. We've found that, Mr. Chairman, in these
18 Niobrara pools it's rather unusual to have under saturated
19 oil and a gas cap but it occurred in Boulder; it occurred
20 in East Puerto Chiquito; it occurred in West Puerto Chi-
21 quito; and it occurred in La Plata Gallup. It's unusual in
22 most reservoirs. In this area it's not so unusual.

23 Now Gavilan undoubtedly had free gas in
24 its highest five wells. The first well produced free gas
25 at a very high rates, so it appears that Gavilan, too, had

1 free gas and I think we've all agreed at least that Gavilan
2 was under saturated. That is one point the opposition and
3 we agreed on was when Gavilan was discovered it was under
4 saturated.

5 Now, you can see a little bit of a
6 change in slope as the pressure dropped through the bubble
7 point and the bubble point was around some 800 pounds, a
8 little over, and so there's a change in slope. Now that
9 change in slope is interesting and we'll explain that in a
10 little more detail later.

11 First I'd like to go to the yellow sheet
12 next and here we have calculated what the gravity drainage
13 potential would be, and that's the last three columns on
14 the righthand side, (13), (14) and (15).

15 Now Standard of Texas, who's also oper-
16 ating in the pool for Mobil, took some bottom hole pressure
17 tests and they came up with high transmissibilities that
18 pretty well confirmed that what appeared to be the case in
19 the Mobil well that pulled (unclear) a day, they show
20 transmissibilities up to 40 to 50 darcy feet.

21 Now it's hard to think of transmissibil-
22 ities that high, but there's no question it was very high.

23 Now, in columns (11) and (12) I show the
24 field oil production in terms of barrels per month and then
25 the rate in terms of barrels per day per linear mile along

1 the strike. Now that's what compares, like in the first
2 line under the date it shows March 1, 1962. The rate was
3 108 barrels per day per linear mile along the strike but
4 the gravity drainage potential was from 10 to 30 times as
5 high as the actual rate of production.

6 Then we come down to May of '63, the
7 rate was up to 300 barrels at the lowest; I show the
8 potential as 500 barrels.

9 Then in '64 the rate was -- production
10 rate was still 300 barrels and now we're getting close to
11 the gravity drainage potential of 10 to 20 darcy feet, but
12 still a very -- the chances are that practically all the
13 production is from gravity drainage, enjoying gravity
14 drainage.

15 Then in '65 is the first time that there
16 was an increase in gas/oil ratio, and I'm not real sure
17 just how that works in this particular instance, because
18 the gas is helping but then on removal of the oil it causes
19 expansion of the gas cap, I doubt that it seriously hurts
20 that gravity drainage rate that much.

21 This is the only time we show the grav-
22 ity drainage rates to be less than the actual production
23 rate, unless, of course, it was higher than 30 darcy feet.
24 It's hard to believe that it was higher than that.

25 Then when the gas/oil ratio drops off,

1 why then the production rate fell below the gravity drain-
2 age rate. Right here is where you can say the gravity
3 drainage rate increased because of the production rate.

4 So we know that in Boulder there's a lot
5 of gravity drainage.

6 Q Okay, could you compare that, compare
7 Boulder to Canada Ojitos as to the percentage of gravity
8 drainage?

9 A Yes, sir. Mr. Chairman, Boulder was
10 developed and produced at about the same time that we were
11 working Canada Ojitos and I was very much, of course, in-
12 terested and I spent a lot of time studying and accumu-
13 lating information on Boulder, and recognizing the high
14 recovery that they have obtained in Boulder and the ques-
15 tion was how do we get that kind of recovery in Canada
16 Ojitos. And as we examined the character of the oil, the
17 probable solution gas drive recoveries, the increased
18 volume of gas in solution, the increased shrinkage, it was
19 clear that we could only look to about 6 percent of the oil
20 in place for Canada Ojitos unless we could enjoy gravity
21 drainage.

22 And there are real problems in realizing
23 gravity drainage where there's a long down dip section,
24 which we had, four or five miles down dip, and when we look
25 at the brown sheets, we can see how disastrous it would be

1 to attempt to produce Canada Ojitos by solution gas drive
2 or like they produce Boulder, they can have no control,
3 they -- they just produce it and thank goodness for the
4 Commission's allowable restriction on rate, why they do
5 manage to get good recovery.

6 If you restricted our rates, just a
7 simple calculation shows that unless the pressure drops, we
8 just wouldn't be able to produce at any economic rates at
9 all, and we show here what the gravity drainage potential
10 would be under typical solution gas drive conditions in
11 which the gas/oil ratio would increase but the pressures
12 decline and we can see that when the gas/oil ratio got up
13 around 1500 to 2000 cubic feet a barrel and we've only got
14 a quarter of the potential, that (unclear.)

15 So it was clear to me that if we could
16 do it, we needed to maintain the pressure. We considered
17 water, we considered gas, and as I analyzed that situation
18 I could see that we could maintain pressure with the gas
19 injection as compared to with water injection with approxi-
20 mately 1/50th (not clearly understood) wells without chan-
21 neling, and that meant to me that we needed to go to,
22 certainly to gas injection, and particularly where we had
23 the situation where we could inject gas with the present
24 structure.

25 Now on the workover sheet you see one of

1 the only problems that you have in a reservoir where one
2 can try to achieve a gravity drainage recovery, and I show
3 here a section of reservoir 4 miles down dip and a mile
4 wide and a recovery well down at the bottom.

5 Now, whatever the gravity drainage
6 potential is for that section of the reservoir, say it's
7 500 barrels a day, but that one recovery well at the bottom
8 can't produce 500 barrels a day, then it's a mistake to
9 drill additional wells.

10 The additional wells will not increase
11 the gravity drainage potential if there's only one gravity
12 drainage potential for that section of the reservoir.

13 So, clearly, the proper thing for us to
14 do was to drill wells on the down dip side of the reser-
15 voir, inject gas at the top, and any intermediate wells
16 just use them for observation wells.

17 And in a sense, that's what we've done.

18 Q Okay, will you now go to the yellow
19 sheet and review that?

20 A Okay. We have some remarks here that
21 gravity drainage has been ineffective and there have been
22 some general remarks made.

23 I think Mr. Weiss stated that high re-
24 coveries and low gas/oil ratios meant effective gravity
25 drainage and effective pressure maintenance operation, and

1 I think that's true. If -- if we had only gas injection,
2 pressure maintenance, with no gravity drainage, then as
3 Mr. Elkins said day before yesterday, the gas would just
4 whistle through those fractures and in a short time the gas
5 would reach the bottom of the structure. We need to hold
6 the injection, maintain pressure, and control the rates so
7 that we do not exceed the gravity drainage rate. That's
8 what happens and we know that because of the low gas/oil
9 ratios that we've had, and the large recoveries with those
10 low gas/oil ratios.

11 I think when we recognize these facts,
12 two important characteristics are evident:

13 1. A large proportion of the reservoir
14 volume is in the high capacity fractures, otherwise, if
15 it's just a small volume even with gravity segregation,
16 then the gas would soon reach the bottom of the structure.

17 2. Gravity segregation has been signi-
18 ficant because of the large volume in the fracture system,
19 if operating under gas drive would have caused early high
20 gas/oil ratios.

21 Q Now, does the remainder of this book
22 just contain supporting information?

23 A Yes, sir.

24 Q Would you now refer to Benson-Montin=
25 Greer Exhibit Number Ten? This is an exhibit passed out

1 this morning entitled Comparison of Efficiency of Recover-
2 ies.

3 A Yes, sir. Let's see, does everybody
4 have Exhibit Ten?

5 Here, Mr. Chairman, we've made a compar-
6 ison of recoveries and I want to say that one way it can be
7 done is to look at the total oil in place and a few other
8 characteristics, and first we'll look at Boulder.

9 Boulder's cumulative production is about
10 1.8-million barrels, and I subtracted from that the produc-
11 tion above the bubble point. Now the reason for that, Mr.
12 Chairman, is when oil is above the bubble point and the re-
13 servoir is produced, then the oil simply expands and at the
14 bubble point, even though you produce some oil the reser-
15 voir is still full of oil, 100 percent saturation, no gas,
16 still 100 percent oil.

17 So the only way we can really, truly
18 compare recoveries and recovery efficiency of the mechanism
19 that's operating, we need to discount the production above
20 the bubble point. So I subtract that, and on line 5 I show
21 that in Boulder they had 1.5-million barrels above the
22 bubble point -- I mean below the bubble point.

23 Now, the oil in place, line 6, Mr.
24 Chairman, I spent a lot of time getting all the information
25 I could to analyze the oil in place in Boulder, and what I

1 found was the best way to analyze it, I believe if you take
2 material balance calculations, conventional ones are going
3 up against some problems. One of these are these steeply
4 dipping reservoirs, there is a significantly different
5 situation than is typical and ordinarily described in the
6 literature as to how to analyze it, because ordinarily a
7 reservoir is relatively flat, relatively thin, and so as
8 the pressure drops down to a bubble point, there'll be a
9 sharp change; go from under saturated oil just in a short
10 time to saturated oil and you have have a sharp change in
11 those conditions. You can calculate rather accurately with
12 your material balance methods what you're dealing with.

13 Now here as the pressure drops and the
14 bubble point drops down the structure, then a significant
15 part of the oil is saturated and a significant part is
16 under saturated, until the bubble point goes all the way to
17 the bottom.

18 Now what I found is that the best way to
19 try to calculate the oil in place is to compare the barrels
20 per pound recovery under one situation with barrels per
21 pound in another situation. By putting the two together,
22 then, we can eliminate some of the unknowns like the free
23 gas cap, which is unknown to begin with. Formation com-
24 pressibility becomes less of a factor, and so that's how I
25 calculated oil in place in Boulder.

1
2 Now the details of that calculation are
3 in the records of the Commission. We filed them, I think,
4 in 1980 in one of the hearings with respect to West Puerto
5 Chiquito.

6 So Boulder, I would estimate, then,
7 5-1/2 to 6-million barrels in place, something like 27 to
8 25 percent of the original oil in place unrecovered in
9 Boulder.

10 Now in Canada Ojitos the -- under line
11 1, we've produced 10-million barrels, and here again it's
12 hard to determine what's the production above the bubble
13 point with the bubble point dropping down, down structure,
14 part of it's saturated, part of it's under saturated, so
15 somewhere around .4, half a million barrels, I think is a
16 reasonable number for that.

17 Then I need to deduct the migration
18 which we discussed earlier, 700,000 barrels there, and we
19 need to deduct the net of the expansion area (not clearly
20 understood) by 1.6-million barrels, I'd estimate about
21 800,000 of that should be deducted from the pressure main-
22 tenance project recovery.

23 So then we come up to a maximum over the
24 bubble point of 1.5, about 8.1 million barrels.

25 Now the oil in place in Canada Ojitos is

1 somewhere between 30, initially 30 to 50-million barrels,
2 and I made that estimate some 20 years ago. There's no way
3 to make a more accurate estimate now.

4 MR. DOUGLASS: I'm sorry, Mr.
5 Greer, I think you said 1.5-million. Did you mean 8.1?

6 A I thought I said 8.1. Did I say 1.5?

7 MR. DOUGLASS: I heard 1.5.

8 MR. CARR: Whatever, which is
9 it?

10 A Mr. Chairman, it's really --

11 MR. DOUGLASS; I was listen-
12 ing, you understand.

13 A Its really heartening, Mr. Chairman, to
14 know that our attorneys are paying that close attention to
15 what you're doing. Sometimes I worry about that.

16 MR. DOUGLASS: We're always
17 trying to learn, Mr. Greer.

18 A So, I came up with 30 to 50-million
19 barrels and I say that that's the best estimate that could
20 have been made then or can be made since.

21 Of course, since that time we've had use
22 of computers come into play, and reservoir simulations and
23 such as that, but there's no way that those methods can
24 improve on this recovery (unclear), that is, that regards
25 the pressure maintenance by gas injection, and if you think

1 about it, on material balance methods, whether you use a
2 computer, slide rule, a calculator, or what, they are based
3 on a pressure response and if, for instance, in a pressure
4 maintenance project you put in just as much as you take out
5 and the pressure stays exactly the same, then there's no-
6 thing to work with. It just doesn't have anything to -- no
7 pressure drop to work with.

8 Now, we had that small pressure drop but
9 these things are out of proportion and -- and so some of
10 the things that undoubtedly creep in, where we have cycled
11 gas so much through the reservoir, it's just the error in
12 computing the volumes of gas; no way to get them perfect,
13 and that alone can cause enough error that there's no way
14 that we can take information since the time we started in-
15 jecting gas (unclear) oil in place.

16 Here again I put the details in the re-
17 cord about how I calculated oil in place again in 1984, and
18 I feel comfortable that that's about the range of the oil
19 in place.

20 Now, there is a lot of Canada Ojitos
21 that has reservoir, as we indicated earlier, that is not
22 commercial, and this volume that I show here for the pro-
23 ject area would be the volume in the project area down to
24 the tight streak, and from that 30 to 50-million barrels we
25 show to date a recovery of 27 percent to 16 percent.

1 And I have the details of how I've
2 estimated the -- the share of expansion area production
3 that should be credited to the unit at the bottom of the
4 page.

5 Then for Gavilan -- Mr. Chairman, I see
6 it's 5:00 o'clock, I'm just about through and this will
7 probably be a good place to stop when I get through with
8 just this one schedule -- it's had a cumulative production
9 of 4-million barrels, this being approximate till 1-1-88.

10 Then less the production above the
11 bubble point, which is just about the same amount as -- as
12 migration -- as migrated, and I have migration to Gavilan.
13 Now that's from the expansion area into Gavilan. That's my
14 estimate -- no, I'm sorry, about 500, 4-to-500 barrels of
15 that I estimate came from the expansion area of the unit.
16 The other 300,000 barrels it's apparent to me has come from
17 the south, the west, and the north, and so Gavilan in a
18 sense has been in a pressure sink and enjoying migration
19 from all directions.

20 The net production from Gavilan is --
21 when I talk about Gavilan here now, it's about a 27,000
22 acre section in the heart of Gavilan, but we'll look at it
23 in more detail later.

24 But for that, that area, that's the
25 volume of oil that we can say was produced from that area

1 below the bubble point.

2 Now, oil in place, I estimated 30 to
3 40-million barrels and we'll look at that calculation to-
4 morrow. That gives a current percent recovery of oil in
5 place in Gavilan of 8 to 6 percent; and I would estimate
6 that perhaps a fourth of Gavilan's recovery is from gravity
7 drainage. There's just no way to escape some gravity
8 drainage in this reservoir as high as the transmissibility
9 is.

10 But it's my feeling at this point the
11 solution gas drive recovery from Gavilan is between 4-1/2
12 and 6 percent. That translates to 68 barrels an acre and
13 the total recovery from both solution gas drive and gravity
14 drainage, that's the G.D. to date, which is 1-1-88, about
15 91 barrels an acre.

16 This is a comparison, Mr. Chairman, of
17 the efficiency of these three pools and it's just so clear
18 to me that the gravity drainage in the pressure maintenance
19 project has been effective and is still working.

20 MR. CARR: May it please the
21 Commission, at this time we think it would be appropriate
22 to break. We're getting ready to have one short exhibit
23 and then go into the rest of the large books; unless you
24 want to go on for awhile this would be an appropriate time.

25 MR. LEMAY: No, a good time

1 for a break for you is a good time for me, so let's
2 reconvene tomorrow at 8:30.

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4 (Thereupon the evening recess was taken.)
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C E R T I F I C A T E

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY the foregoing Transcript of Hearing before the Oil Conservation Commission was reported by me; that the said transcript, contained on pages 750 through 989, inclusive, is a full, true and correct record of this portion of the hearing, prepared by me to the best of my ability.

Sally W. Boyd CSR

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