STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

JUN

IN THE MATTER OF THE HEARING)
CALLED BY THE OIL CONSERVATION)
DIVISION FOR THE PURPOSE OF)
CONSIDERING:) CASE NOS. 11,194
) and 11,195
APPLICATIONS OF GILLESPIE-CROW,) (Consolidated)
INC.)
)

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: DAVID R. CATANACH, Hearing Examiner

June 16th, 1995

Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Division on Friday, June 16th, 1995, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, before Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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I N D E X

June 16th, 1995
Examiner Hearing
CASE NOS. 11,194 and 11,195 (Consolidated)

(Continued...)

* * *

EXHIBITS

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APPEARANCES

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By: FRANK N. CREMER

* * *

WHEREUPON, the following proceedings were had at 8:23 a.m.:

EXAMINER CATANACH: At this time we'll call the hearing back to order, and I will call Case 11,194, which is the Application of Gillespie-Crow, Inc., for approval of a pressure maintenance project and qualification for the recovered oil tax rate pursuant to the "New Mexico Enhanced Oil Recovery Act", Lea County, New Mexico.

At the request of the Applicant, we will also call at this time and consolidate Case 11,195, which is the Application of Gillespie-Crow, Inc., for statutory unitization, Lea County, New Mexico.

Are there appearances in these cases?

MR. BRUCE: Mr. Examiner, Jim Bruce from the Hinkle law firm in Santa Fe, representing the Applicant.

I have five witnesses to be sworn.

MR. KELLAHIN: Mr. Examiner, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin, appearing on behalf of Snyder Ranches, Inc., and Larry Squires.

I have two witnesses to be sworn.

MR. CREMER: Mr. Examiner, my name is Frank Cremer. I'm with the firm of Turner and Davis in Midland, Texas. I represent Phillips Petroleum Company.

Phillips is here today in support of the formation of the unit and the implementation of the pressure maintenance program as proposed by Gillespie.

We're not certain that we're going to call any witnesses, but we have three potential witnesses.

EXAMINER CATANACH: Any additional appearances?

Will all the witnesses please stand to be sworn in at this time?

(Thereupon, the witnesses were sworn.)

MR. BRUCE: Would you please state your name for the record?

MR. KELLAHIN: Excuse me, Mr. Examiner. Excuse me, Mr. Bruce. I have a short opening statement, if that's appropriate at this time, Mr. Examiner.

EXAMINER CATANACH: Okay.

MR. KELLAHIN: Mr. Examiner, I wish to share with you what I think our evidence will demonstrate and to tell you a few things about what this case is not.

This is not a waste case. My witnesses are not here to oppose the concept of pressure maintenance. In fact, our evidence will support the concept that it's appropriate to institute gas injection in this reservoir, to optimize oil recovery, and so we support the Applicant in the concept of a gas-injection pressure-maintenance project.

We are here to recommend to the Division a change in the participation formula. We believe that that will be necessary in order to protect correlative rights. Our technical witnesses will show you how we believe that the principles of correlative rights can be protected with the adjustment in the participation formula.

There is a fundamental disagreement between the parties. We believe that the shape of the reservoir, as mapped by the Applicant, does not represent a correct distribution of the hydrocarbon pore volume of the reservoir. That is of significance to my experts, because the method by which each tract participates in the unit and receives relative value for that participation is based upon an accurate pore volume distribution map from which all the rest of these items flow.

So as the presentation is made, you'll see from our experts that we have substantial disagreement with the Applicant when it comes to the distribution on the hydrocarbon pore volume map.

That issue and the participation formula are the items that we're here to present technical evidence on, and at the conclusion of our presentation, we hope that we have persuaded you to alter the participation formula and to adopt our hydrocarbon pore volume map.

Thank you.

MR. BRUCE: If I could say something, Mr. Examiner, of all the exhibits you'll see, there's a couple that are hydrocarbon pore volume maps, Snyder Ranch's and ours, that will be the main bone of contention.

And we will show evidence today that pore geologists and pore geophysicists from three different companies have looked at the data, 3-D seismic data, geological data, and have all agreed on the contouring. Snyder Ranches' geologists looked at this data without the seismic, and frankly, we think they came up with an incorrect interpretation. I would note that that 3-D seismic was made available to Snyder Ranches. They did not incorporate it in their maps.

Now, there are three main working interest owners in this unit: Phillips, Gillespie and Dalen, which has just been bought out by Enserch. Together, Gillespie and Dalen have about -- I forget the exact percentage, but somewhere around 93 percent of the working interest in the unit.

Frankly, the interpretation put forth, or that will be put forth by Snyder Ranches, would result in Dalen and Gillespie getting a couple extra percent in the unit. So their formula favors my client. But they're not here proposing that, because they don't think it's fair.

So I think we just want you to keep in mind while you're hearing the evidence that what you will see is a formula that fairly allocates the substances to each tract.

Are you ready, Bill?

WILLIAM CROW,

the witness herein, after having been first duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Would you please state your name for the record?

A. William Crow.

Q. What is your occupation?

A. I'm a geologist.

Q. And who do you work for?

A. I am president of Gillespie-Crow, Incorporated, the operator of the proposed unit. I am also the geologist and operations manager for Charles B. Gillespie, Jr., who drilled all 11 wells in the proposed unit area.

Q. And have you previously testified before the Division as a geologist?

A. Yes.

Q. And were your credentials as an expert petroleum geologist accepted as a matter of record?

A. Yes.

Q. And are you familiar with the geological matters pertaining to the West Lovington-Strawn Pool and the proposed unit?

A. Yes.

MR. BRUCE: Mr. Examiner, I tender Mr. Crow as an expert petroleum geologist.

EXAMINER CATANACH: Mr. Crow is so qualified.

Q. (By Mr. Bruce) Briefly, Mr. Crow, what is it that Gillespie-Crow, Inc., seeks in these two Applications?

A. In Case Number 11,195, Gillespie-Crow, Inc., seeks to unitize the Strawn limestone interval underlying 1458.95 acres of state, federal and fee land in Lea County.

In Case Number 11,194, we seek approval of a pressure-maintenance project for the unit and certification for the recovered-oil tax rate.

Q. Why are you proposing unitization?

A. We propose unitization to perform secondary recovery operations through gravity-stabilized natural gas displacement by injecting natural gas into the top of the Strawn reservoir for pressure-maintenance purposes.

The reservoir is approaching critical gas saturation, at which time gas-oil ratios will rise rapidly, and oil production is expected to decline dramatically. This will leave a large majority of the original oil in place unrecovered unless unitization and pressure maintenance is initiated. Pressure maintenance is projected to recover an additional 1.6 to 2.3 million barrels of incremental secondary oil.

Q. Would you refer to your Exhibit Number 1, identify it for the Examiner, and describe its contents?

A. Exhibit 1 is a land plat which outlines the proposed unit area and which identifies the separate tracts which comprise the unit area. The tracts were formed according to common mineral ownership. There are 11 tracts in the unit area, all operated by us.

Q. And how was ownership of these 11 tracts determined?

A. We have title opinions on all tracts. Thus, the interest owners set forth in Exhibit B to the unit agreement are correct and current.

Q. And what is the unitized formation? And I would refer you to your Exhibit 2.

A. The unitized formation is the entire Strawn limestone interval.

Exhibit 2 is a portion of the compensated neutron lithodensity log from the Speight Fee Well Number 1. It's located in lot 3 of Section 1, Township 16 South, Range 35 East.

The top of the Strawn limestone is found at 11,420 feet, and the base of the Strawn limestone is found at 11,681 feet.

The unitized formation includes all correlative depths in the unit area. The unitized formation is the designated and undesignated West Lovington-Strawn Pool.

Q. Would you describe the history of the pool?

A. The West Lovington-Strawn Pool was discovered in June, 1992, when Charles Gillespie, Jr., completed the Hamilton Federal Number 1 well, flowing 408 barrels of oil a day and 1200 MCF of gas a day from Strawn perforations at 11,500 feet and 11,570 feet.

A drill stem test taken over a large portion of the producing interval in this well measured the original bottomhole pressure of the reservoir to be 4392 p.s.i.

A confirmation well was drilled in September of 1992. This well, the Speight Fee Number 1, was completed flowing 520 barrels of oil a day and 1082 MCF of gas from Strawn perforations at 11,424 feet to 11,548 feet.

Mr. Gillespie has drilled and completed a total of 11 flowing wells in the pool without drilling any dry holes and currently operates every well associated with the pool in the proposed unit.

Our Wiley Fee Well Number 1, located in the southwest quarter of the northeast quarter of Section 33, Township 15 South, Range 35 East, identified an oil-water contact along the north edge of the pool at a subsea elevation between minus 7615 and minus 7620.

The last well drilled, the Klein Fee Number 1, located in the northwest quarter of the northeast quarter, just north of the Wiley well in Section 33, confirmed this oil-water contact when it flowed oil, gas and water to surface during drill stem tests taken across the entire Strawn porosity section. This test was taken in March of 1995.

The bottomhole pressure of the reservoir at that time was measured to be 3363 p.s.i., indicating a 1029 p.s.i. drop in bottomhole pressure across the pool since June of 1992.

At this time -- At the time this last bottomhole measurement was taken, Charles B. Gillespie, Jr., had produced 1,304,900 barrels of oil and 2,519,480 MCF of gas from the pool.

Q. Okay. Would you refer to your Exhibits 3 and 4 together, please, and identify them for the Examiner?

A. Exhibit 3 is an isopach of the net porosity greater than or equal to 3 percent.

Exhibit 4 is a structure map contoured on top of the Strawn limestone.

Q. Would you discuss for a while the geology in this pool?

A. Okay, the Pennsylvanian Strawn formation produces stratigraphically trapped oil from phylloid algal mounds or mound reservoirs developed along the lower shelf margin north and northwest of the Central Basin Platform.

Primary porosity has been enhanced within these

Strawn bioherms by freshwater dissolution of bioclastic material during periods of subareal exposure.

These mounds are sealed laterally by flanking tight mudstones and vertically by densely cemented grainstones and shales. It is this facies relationship of thick, porous mound buildup versus thin, tight flanking beds that creates subtle seismic anomalies such as the one that led to the discovery of the West Lovington-Strawn Pool.

This algal mound reservoir, the one for the pool, is approximately one and a half miles in diameter, and attains a maximum thickness of 131 feet of net limestone porosity greater than or equal to 3 percent PHI, where PHI equals density porosity times 85 percent.

Subsurface structure mapping on top of the Strawn limestone throughout the proposed unit indicates a broad structural nose plunging northwest with possible closure existing on the south end of the field, immediately south of the Speight Fee Well Number 1 in Lot 3 of Section 1.

Dip throughout the unit is to the north northeast, towards Tatum Basin.

Q. Would you identify your Exhibits 5 through 8 and go through them for the Examiner?

And during that process describe how the unit boundaries were selected.

A. Exhibits 5, 6, 7 and 8 are structural cross-sections.

Cross-sections A to A', B to B', and C to C' correlate the wells in the unit from west to east across the unit, starting from the north side, and work their way to the south.

And cross-section D to D' correlates wells from the south end of the unit toward the north, across the middle of the unit.

The proposed boundaries of the West Lovington-Strawn Pool are based to the east where Bridge Oil Company drilled the Julia Culp Number 2 well located in the east half of Section 34, Township 15 South, Range 35 East, and well control to the west where Amerind Oil Company drilled the West State Number 1, located in lot 1 of Section 2, Township 16 South, Range 35 East.

Electric logs shown on the cross-sections from both of these wells show that the porosity interval, which is producing in Mr. Gillespie's wells, pinches out laterally east and west, and it's indicated on cross-sections A to A', B to B' and C to C'.

So this gives us a good indication of where the wells and the east boundaries of the pool are.

Also in the very southeast corner, if you look at cross-section C to C', the dip and the thinning of the reef section from the Earnestine 1 well to the Earnestine 2 well gives a good indication that the next location over in Section 6 on tract 6 is probably right at the edge of the reservoir.

The north boundary of the unit is also based on well control which defines a downdip oil-water contact at a subsea elevation of approximately minus 7617. This is shown on cross-section D to D'.

Finally, the south boundary of the unit is based on geological and seismic interpretations of all the well data and seismic data available within the immediate area.

The south edge of the producing Strawn mound being unitized is easily identified on proprietary 3-D seismic data.

Q. Would you please identify Exhibit 9 for the Examiner?

A. Exhibit 9 is an isopach map of the hydrocarbon pore feet for the West Lovington-Strawn Pool. This is based upon electric log calculations utilizing the oil and gas industry's state-of-the-art Geographics QLA2 software program, which was jointly developed by Geographics and Schlumberger. Another witness will discuss these calculations.

This map forms the basis for the unit participation.

Q. In your opinion, does the data available from this pool support the proposed unit boundaries as set forth by Gillespie-Crow, Inc.?

A. Yes.

Q. And has the pool been adequately defined by development?

A. Yes, it has.

Q. Referring to Exhibit 9A, how will production be allocated among the tracts?

A. Exhibit 9A is the participation formula set forth in Section 13 of the unit agreement.

Each tract's participation is based upon its calculated original oil in place, less production to May 1 of 1995 from that tract. I think the second -- Is there a second-page attachment to that which gives the actual calculations, tract by tract?

Q. In your opinion, does the participation formula contained in the unit agreement allocate the produced and saved hydrocarbons to the separate tracts on a fair, reasonable and equitable basis?

A. Yes, each tract will receive its proportionate share of hydrocarbons in the pool, even if it's not produced today. Thus, no one is penalized.

Q. For a minute here, Mr. Crow, I'm going to have you act as a landman, but you were the one primarily involved in discussing with the working interest owners the proposed unitization on behalf of Charles Gillespie or Gillespie-Crow, were you not?

A. Yes, sir.

Q. Would you refer to Exhibit 10, and without going into -- without repeating everything that's on Exhibit 10, would you discuss the meetings with the working interest owners which you did in order to get them to agree to the unitization of this pool?

A. Okay, Exhibit 10 is a timeline giving dates of meetings, phone conversations and correspondence with various working interest owners.

Gillespie and Dalen Resources Oil and Gas Company, then known as PG&E Resources Company, began looking into possible pressure maintenance of the West Lovington-Strawn Pool as early as April of 1993, just ten months after the completion of the discovery well.

Numerous meetings and conversations were held with Dalen up through August of 1994, looking into the possibilities of water-flooding the reservoir versus natural gas or CO_2 injection.

After it was determined that natural gas injection would be the most efficient and economic project, we approached Phillips Petroleum Company with the idea in late August of 1994.

Gillespie then notified all the working interest owners by certified mail of his intent to unitize the pool in September of 1994.

Numerous correspondence and conversations with working interest owners occurred throughout the fall of 1994, till a formal working interest owners' meeting was proposed and held at Gillespie's offices on November 17th. All working interest owners were notified of this meeting by certified mail.

After all the working interest owners reviewed the data Gillespie presented at the meeting, ratifications and joinders to the proposed unit agreement and operating agreement were requested in December of 1994.

A hearing with the OCD was then scheduled for mid-January of 1995.

Prior to this hearing, some of the working interest owners requested that an additional well be drilled by Gillespie for added well control, and due to continuous development clause under tract 6, which required Gillespie to drill a second well on its Snyder Ranches lease about mid-March, Gillespie drilled and completed two more wells in the pool by April of 1995.

After the geological and engineering data from these new wells was incorporated with the existing data previously used, slight adjustments were made to the tract participation numbers originally proposed, and new unit operating agreements and exhibits were sent certified in May to all the working interest owners remaining in the unit.

Following several Q-and-A phone conversations with all the working interest owners or their legal representatives, all working interest owners agreed to and ratified the current unit documents.

Q. So there's 100-percent commitment on the working interest owners?

A. There's 100-percent commitment of the working interest owners.

Q. What is Exhibit 11?

A. Exhibit 11 is the proposed unit operating agreement.

Q. And as you said, they've all approved the operating agreement?

A. Yes, they have.

Q. In your opinion, is the operating agreement fair and reasonable?

A. Yes, it's based on other operating agreements approved by the Division. It sets forth the duties and authority of the operator, as well as the apportionment of unit costs.

Q. And does the operating unit agreement contain a provision for carrying working interest owners?

A. Yes, in Section 11.6.

Q. And does it provide for a penalty to be assessed against any working interest owners who do not consent to any unit operations?

A. Yes, and Section 11.6 provides for cost plus 200-percent nonconsent penalty.

Q. In your opinion, is that a fair penalty?

A. Yes, operating agreements in this area typically provide for similar nonconsent penalties.

Q. In your opinion, will the unitization of this pool, of this unit, be in the interests of conservation and the prevention of waste?

A. Yes, the proposed West Lovington-Strawn unit is a large Pennsylvanian Strawn phylloid algal mound having excellent vugular homogeneous porosity and permeability.

The reservoir is approaching critical gas saturation due to a 1000-pound-plus p.s.i. drop in bottomhole over the last three years. Unless unitization and pressure maintenance is initiated in the near future, a large percentage of the original oil in place will not be recovered.

Q. Were Exhibits 1 through 11, except for Exhibit 9, prepared by you or under your direction?

A. Yes, they were.

MR. BRUCE: Mr. Examiner, I'd move the admission of Gillespie's Exhibits 1 through 8 and 10 and 11 at this time.

EXAMINER CATANACH: Exhibits 1 through 8, 10 and 11 will be admitted as evidence.

Mr. Kellahin?

MR. KELLAHIN: Yes, sir. Thank you, Mr. Examiner.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Crow, if I look at your Exhibit 10, over on page 2, in approximately November and December of last year, in 1994, formal meetings were taking place among the working interest owners at which there was geologic and engineering data presented as to the pressure-maintenance project?

A. That is correct.

Q. All right. As of that time, had you selected a particular tract participation formula as we see it presented today in Exhibit 9A?

A. We had a formula that we did propose to the working interest owners.

Q. Is that this formula I see on Exhibit 9A?

A. No, it's not.

Q. When did the formula that's shown on 9A become the formula adopted by the working interest owners?

A. After the working interest owners had a chance to review and we had several more meetings with Phillips -- I can't recall exactly; it was sometime, I believe, in January or February that we decided that there was too many unknown factors in the original proposed formula, and so we just came back with a new idea.

Q. All right. The formula I see that was adopted by the working interest owners on Exhibit 9A was adopted by those owners prior to drilling either the Klein 1 or the Snyder 2 well?

A. Yes.

Q. The participation formula that was adopted as shown on Exhibit 9A, was that based upon the geologic work that you and others had done in November and December of 1994?

A. Would you repeat that again? I didn't --

Q. Yes, sir. The working interest owners, in approximately January of 1995, have agreed upon the current formula that the Examiner sees, all right?

A. Okay.

Q. Isn't that right?

A. Yes.

Q. Prior to that date, you had a set of maps dealing with the pressure-maintenance project, including a structure map, an isopach, and a hydrocarbon pore volume map, did you not?

A. Yes, sir.

Q. And those maps were generated approximately November of 1994?

A. Approximately, yes.

Q. All right.

A. Well, they were generated throughout the whole -- They were being built up as we built the field, but they were finalized about that time, yes.

Q. Okay. Let me show you, Mr. Crow, what I have marked as Snyder Exhibit Number 1 and have you go through this, before we discuss it with the Examiner, and make sure that I have shown you the geologic maps that were being used in November of 1994. If you'll take a moment and look at that.

A. I believe these are the maps that were being used.

Q. All right, sir. And the last attachment, then, is a spreadsheet indicating the pore volume calculations and distributing it among the various tracts?

A. Yes, uh-huh.

Q. That was provided to me either through you or through Mr. Bruce.

Can you authenticate the accuracy of these displays as to this period of time?

A. I believe these are the numbers we presented, yes, sir.

MR. KELLAHIN: All right, sir.

Mr. Examiner, I show you what I've marked as Exhibit Number 1. It's the document Mr. Crow and I have been discussing. I would at this time move the introduction of Snyder Exhibit Number 1.

EXAMINER CATANACH: Snyder Exhibit Number 1 will be admitted as evidence.

Q. (By Mr. Kellahin) If you'll turn behind the cover sheet of Mr. Bruce's letter to me and look at the first display, Mr. Crow, it's a structure map.

A. Uh-huh.

Q. It bears the notation that Mr. Ralph Nelson, Dalen's geologist, drafted this in November of 1994.

Did you have any part in drafting or analyzing or verifying the accuracy of this structure map?

A. Yes. I mean, Ralph did the mapping, but we -- Gillespie had its own set, and they were always very similar, and we -- I verified his tops and everything, yes, sir.

Q. All right. So when I talked to you about Mr. Nelson's map here, it's information that you have looked at, understand and agree with?

A. Yes.
Q. All right. Give me the approximate vintage of the 3-D seismic data that has been accumulated in the area.
A. You mean when did we shoot it? Is that what --
Q. Yeah, when did you shoot it, process it and have it available to you and the other scientists to utilize?
A. We shot the 3-D data after we had drilled the fifth well, which was -- We had drilled the Hamilton 1, the Hamilton 2, the Speight Number 1, the Earnestine 1 and the Earnestine 2.
We developed five wells with 2-D data, felt at that time that was about as far as we could go without risking a dryhole with the present data we had, and came back and shot the 3-D data at that time --
Q. Do you have an approximate date? Can you give me a year?
A. I'm trying to recall when. You know, this has gone on and on. I want to say it was January, 1994. I'd have to go back and verify.
Q. It certainly is prior to generating these displays that we're looking at now?
A. Yes.
Q. Okay. Does this structure map integrate any of the 3-D seismic information, conclusions and opinions of those experts in how it was drafted?

A. You would have to ask Ralph if they used 3-D to interpret their structure on this map.

Q. You do not know?

A. I do not know.

Q. On this map there is a notation just below the Wiley 1 well in the southwest-northeast of 33, and the notation says "oil-water contact at minus 7617".

A. Uh-huh.

Q. That's based upon log analysis of the Wiley Number 1 well, is it?

A. That is correct.

Q. I believe you told Mr. Bruce just a while ago that that still remains your opinion about the oil-water contact in the reservoir?

A. We believe that that is still the oil-water contact.

Q. Subsequent data generated from after November of 1994 has not changed that opinion or conclusion?

A. No, the Klein well just confirmed that, in our opinion.

Q. When you prepared your own analysis of the structure --

A. Uh-huh.

Q. -- did you have the 3-D seismic data available to you?

A. Yes.

Q. Did you use it when you helped analyze and review this structure map?

A. Yes, I used a consulting geophysicist, and together we used our interpretation into our structural interpretation, yes.

Q. Is it fair to say that as far as you're concerned, all that seismic data has been appropriately integrated into the structure map that we're looking at right now?

A. No.

Q. Why not?

A. Well, I believe that as our newer maps show, that there's more of a saddle existing up here along the section line between 33 and 34 than this map shows.

Q. All right. As wells were drilled utilizing the 3-D seismic information, did you in fact target well locations based upon that data?

A. All locations have been based upon what looked to be the best off 3-D.

Q. On 3-D?

A. Yes.

Q. And as you drilled each well, did you subsequently have people re-interpret or re-analyze the seismic data?

A. After the well was drilled?

Q. Yes, sir.

A. Yes, sir.

Q. Okay, with what results?

A. They usually tied pretty well. Most wells are drilled out close to what we expected, some maybe five, ten feet more porosity, some five, ten feet less. But overall we've been very pleased with our success.

Q. Let's turn to the isopach, which is the next display. Again, this is prepared by Mr. Nelson.

Did you have any input, involvement with analyzing or reviewing or verifying the accuracy, in your opinion as a geologist, with regards to Mr. Nelson's isopach?

A. Yes.

Q. And what conclusion did you reach?

A. This is very close to my interpretation. I like this map a lot, and I verified all the thicknesses.

Q. All right. And the only things that have changed after this map has been generated is the results of the Klein 1 well up in the northwest of the northeast of 33, and the Snyder 2 well in the southwest-southwest of 34? That's the only additional data since you did this map, right?

A. That's the only essential well data, yes.

Q. All right. Is there any other geologic data, other than the data from those two wells?
A. Well, there was some discussion on some more with Phillips about the seismic interpretation.
Q. I'm talking about well data.
A. No, there's no other well data.
Q. You said essential well data, that -- That's, in fact, all the well data?
A. I mean, that is -- Yes, that is the only well data since this map was done.
Q. Where does Phillips have its interest?
A. Under the Hamilton lease.
Q. Any other tracts?
A. No.
Q. Just the Hamilton?
A. Uh-huh.
Q. All right. Then the next display is the hydrocarbon pore volume map.
A. Uh-huh.
Q. It says the geologist is Mr. Scolman. He's with Dalen, is he not?
A. Yes, he is.
Q. Did you have any involvement in preparing, reviewing or validating the hydrocarbon pore volume map that we're now looking at?

A. I did not have any involvement in preparing this, but I reviewed all the data and hydrocarbon pore feet numbers they were calculating with their QLA2 program.
Q. Did you have any disagreement?
A. No.
Q. To generate a hydrocarbon pore volume map, you need to go through an exercise to determine the porosity values in each of the wells, don't you?
A. Yes.
Q. All right, and that is accomplished by an analysis of the log information for each well; is that not true?
A. Correct.
Q. All right. Did you do the log analysis for the wells that generated this hydrocarbon pore volume?
A. I did not.
Q. Who did the log analysis?
A. Mr. Ralph Nelson.
Q. Did any other geologist, other than Mr. Nelson, do the log-analysis work that generated the porosity values that went into this hydrocarbon pore volume map?
A. None that I know of.
Q. All right. As to the hydrocarbon pore volume map that you introduced a while ago as Exhibit Number 9, did you have any involvement with the log analysis that

calculated and picked the porosity values that went into that map?

A. No.

Q. Who did?

A. Mr. Ralph Nelson.

Q. Any other geologist involved in the log analysis?

A. None that I know of.

Q. All right. On January 19th, 1995, Mr. Crow, you testified before Examiner Stogner in the case that resulted, based upon Gillespie's application for 80-acre oil spacing in the West Lovington-Strawn Pool, did you not, sir?

A. Yes, sir.

Q. As part of that testimony, you presented a structure map and an isopach map, did you not?

A. Yes, I did.

Q. Let me show you what I have marked as Snyder Exhibit Number 2 and Snyder Exhibit Number 3 and ask you if these are not copies of the map utilized in that hearing.

A. These are the maps that -- Yes, sir.

Q. All right, sir. Let me have you take the first sheet off of each one, and that way you'll have a copy.

When you look at Exhibit Number 2, Snyder Exhibit 2, Mr. Crow, it's the structure map that was presented in January of 1995?

A. Uh-huh.

Q. Let's come back and compare it to the structure map that we just talked about that was the November, 1994, map that Mr. Nelson had prepared.

A. Uh-huh.

Q. Exhibit Number 2 shows that you're the author of that map. It's dated January 10th of 1995. Did in fact you prepare the map?

A. Yes, I did.

Q. There are differences in the two interpretations of structure at this point, are there not?

A. There are some slight differences, yes.

Q. Describe for us the differences.

A. The -- From what I see, the Dalen map shows a lower subsea elevation in the saddle to the north, on the section line between 33 and 34. I see maybe a couple of feet difference in top picks.

Q. Between November 10th of 1994 and January 10th of 1995, there is no new data by which to change the map, is there?

A. No, except there's -- the two differences in this is -- and you need to ask Ralph. I assume this was probably done based upon his interpretation of the well control and seismic.

This map, I used no seismic at all. This is

strictly mapped solely on well-log control.
Q. And the additional log control became available in April of 1995, after the Klein 1 and the Snyder 2 were drilled and completed?
A. Additional well control after that, yes.
Q. All right. Let's turn to Exhibit Number 3, which is the isopach map. It's dated January 10th of 1995. It shows you to be the author. Did in fact you do the porosity map, the isopach?
A. Yes, I did this one.
Q. Okay. When you look at the isopach map that Mr. Nelson generated, which is part of Snyder Exhibit 1, are there differences between that exhibit and the January, 1995, map that you did?
A. I see very little differences.
Q. Okay. In January 19th of 1995, we had a discussion before the Examiner about the different pieces of information that were available to you with regards to this reservoir, and some of that information had to do with pressure information and the determination of the reservoir bubble point.
A. Yes.
Q. Is that not true?
A. Uh-huh.
Q. All right. At the time we had the discussion in

January, the reservoir had been drawn down below the bubble point, had it not?

A. Correct.

Q. All right. So we were liberating free gas in the reservoir at that time, were we not?

A. I'm not a reservoir engineer, but I understand that -- yes, that's what would be occurring.

Q. At the time we discussed this isopach and structure map, you and I went around the entire boundary of this reservoir, as mapped, and discussed all the components that caused you to decide what that boundary was, did we not?

A. I guess -- I don't recall that. I guess so.

Q. When you presented the maps in January, Mr. Crow, did you find any geologic barriers to provide discontinuity in the reservoir?

A. No.

Q. It appears to be a homogeneous oil reservoir, doesn't it?

A. Yes.

Q. And geologically, it would appear that withdrawals at one point in the reservoir ought to be affecting all portions of the reservoir?

A. If you -- As you deplete the pressure, fluids and gas in the reservoir are going to expand.

Q. And when we look at the geology, there is no discontinuities, irregularities or nonconformities that would break the opportunity to flow hydrocarbons throughout the reservoir?
A. None that we've been able to distinguish.
Q. Do you have an estimate of what you think primary oil production will be in the reservoir?
A. We've made a best-effort attempt based upon decline curve to find out what that is.
Q. What's your understanding of what that primary percentage is?
A. Between 14 and 16 percent.
Q. When gas maintenance is initiated, gas injection is initiated, do you have an opinion as to what the secondary percentage of recovery would be?
A. No, we do not.
Q. All right.
A. We have a -- what we feel like is a conservative estimate. We can't pinpoint exactly what the secondary recovery will be.
Neither can we on the primary. I mean, it's a best estimate that we can give.
Q. All right, sir. What is your best estimate of what that recovery would be, in terms of percentage?
A. On secondary?

Q. Yes, sir.

A. Thirty, 35 percent.

Q. All right. So when we finish primary and secondary recovery, what percentage of the original oil in place do you anticipate that we'll have withdrawn from the reservoir?

A. When we -- State that again, please?

Q. Yes, sir. When you take the primary and the secondary together and the project's done, what percentage of oil in place are you going to recover?

A. We don't have any idea -- we're -- We feel very conservative about running economics at 30 percent. We feel comfortable we'll get that.

Q. I'm not --

A. That's total, that's primary and secondary together.

Q. All right, that's what I'm asking you. Primary and secondary --

A. It could go up very high, but we don't know. And that, to us, really doesn't matter. As long as it's economic to do the project, is all that we're -- And we feel very comfortable that we're going to at least achieve that.

Q. My only question is, the 30 percent represents the total primary and secondary?

A. That we ran economics on.

Q. Yeah, I don't take 30 percent and add 14 or 16 to it?

A. No.

Q. Okay. Thirty percent represents a conservative estimate of recoveries after primary and secondary?

A. Yes.

Q. Okay. Mr. Crow, on page 30 of the transcript that was generated from the January 19th hearing, I asked you this question: "When we look at the northern boundary..." and we're looking at your structure map and your isopach here "...what is your control basis for determining where the zero line is for the northern boundary of the pool?"

And your answer is, "The zero line depicted there to the north was determined using 3-D seismic data interpretation."

A. That's true.

Q. All right.

Question: "How did that help you determine where that zero line was?"

And you go on to describe it.

My question is, when we look at the isopach and the structure map from the January hearing, those have included an integration of 3-D seismic, haven't they?

A. Not the structure map. The isopach has. My structure map that I've presented for the pool hearing did not use any seismic interpretation. It's strictly -- I contoured off wellbore.

Q. Okay. You're using seismic -- 3-D seismic data to give you a porosity value in the reservoir?

A. No, we're trying to depict where the porosity stops, where the mound ends, so we can pick the edges. We don't try to -- we have not -- I don't know if Dalen has, but Gillespie has not tried to model to see how thick it is as you go through the reef.

Q. All right. Often we see seismic work, including 3-D seismic work in a structural analysis, trying to find structure in a reservoir.

A. Oh, yes.

Q. All right. That's not the application here, is it?

A. That's not what I did. Dave has worked a lot with the structure of -- the interpretation of the structure.

Q. All right. So you're using the 3-D seismic work on this isopach to try to give you a reservoir thickness value on the edge of this reservoir; is that what you're saying?

A. No. No, I --

Q. Tell me what you're saying.

A. All I used 3-D for was to try to determine where the edge of the reservoir is. I never tried to use it to determine how thick it was.

Q. How would you utilize 3-D seismic work to give you the edge of the reservoir?

A. I have seen enough seismic data in the Strawn that I know the signal that displayed -- what a reef looks like. And you can follow it, you can see where it stops. Just strictly off the traces, the signals.

Q. We're at 7000 to 8000 feet below surface?

A. We're at almost 12,000 feet.

Q. 12,000 feet below surface --

A. Correct.

Q. -- and we're looking for some little indication on this seismic that will tell you the edge of the reservoir?

A. No, you try to find the thickest part of it, and then you develop out. But the quality of the 3-D data we have, we feel, is -- gives us a pretty good indication of where the edge is, yes.

Q. All right. And you used that stuff when you prepared this isopach that's shown on Exhibit 3?

A. We used it -- I used it to try, my best effort, to define the zero line.

Q. Okay. In December, after this technical information is generated, Gillespie made a formal proposal to the working interest owners and sent out a formal letter over Mr. Conner's signature, I believe; is that not correct?
A. That's correct.
Q. All right. That proposal included a configuration of the unit that's the same configuration we have today. The unit boundary didn't change, did it?
A. Yes, it did not change.
Q. All right. The tracts within the unit remain the same configuration, right?
A. Right.
Q. Tract numbers didn't change, nothing changed in terms of how they were shaped and sized?
A. That's correct.
Q. When that information went out, there was an operating agreement attached to it that showed the values of each of the tracts on Exhibit C, did it not?
A. Correct.
Q. Between that information in December and the revised information that was sent out in May, the change that has been made represents a readjustment in the hydrocarbon pore volume distribution, does it not, Mr. Crow?

A. Yes, it does.

Q. In terms of a change in the ownership between the parties involved in December and the parties involved in May, were there any changes in ownership?

A. Yes, there were.

Q. In what tracts did that ownership change occur?

A. In tracts 10 and 11.

Q. Up in the north half of the northeast of 33?

A. North half, northeast of 33.

Q. All right.

A. When the well was drilled, we had -- Dalen and Gillespie had partners, David Petroleum, et al., being David Petroleum, McMillan Production Company --

Q. I'm sorry, I can't hear you.

A. David Petroleum, McMillan Production Company and Permian Exploration. It's all -- they're all -- just go under David, really.

And they had a small -- Well, they had a 40-percent working interest in that well. And after that well was drilled, they elected to sell out their interest to us.

Q. All right. In tracts 10 and 11, David Petroleum, Colin McMillan, that group that I would know by David Petroleum --

A. Uh-huh.

Q. -- had a 40-percent interest in each of those two

40-acre tracts?

A. No, they had a 40-percent interest in the proration unit --

Q. All right.

A. -- across the 80 acres.

Q. A 40-percent interest in the proration unit?

A. (Nods)

Q. After they sold out, who acquired their interest? How was that distributed?

A. Gillespie and Dalen purchased it.

Q. And you acquired an interest too, didn't you?

A. Oh, yes, I have two and a half percent. I get -- I buy a deal with Mr. Gillespie, five percent of whatever -- proportionately reduced to whatever his interest is.

Q. All right. So you acquired an interest in tracts 10 and 11 that you didn't have back in December?

A. An additional interest.

Q. Yes, sir.

A. I had interest going in.

Q. You picked up an additional interest out of those tracts?

A. But I picked up an additional out of those tracts, yes.

Q. All right. Let's come back now to today's exhibits that you have presented, and let's look at Exhibit

3 and 4. You presented them together. Let's look again at them together.

All right, if we look at Snyder Exhibit 2, which is your structure map from January of 1995, and look at your Exhibit 4, which is your structure map today --

A. Uh-huh.

Q. -- it's a May, 1995, map -- you have altered your structural interpretation, haven't you?

A. Slightly, yes.

Q. All right. What I'm looking at is the northwest quarter section of 34, in which you have projected a structural nose --

A. Uh-huh.

Q. -- that runs from north to south.

A. Uh-huh.

Q. That's an interpretation of a structural nose that doesn't exist to that degree when we look at my Exhibit 2 from the January hearing?

A. That's correct.

Q. You've altered it?

A. This map, once again, is based -- Because it was the basis for the hydrocarbon pore volume map, goes back and interprets the seismic. So it is a combination of well control and seismic interpretation.

Q. What well-control data out of the Klein Number 1 well causes any change in structure?

A. The well was drilled out structurally, just about like the first map shows, what we expected.

Q. All right. So there's nothing geologically in the data available from the logs on the Klein 1 well to justify a change in structure?

A. Well, it gave us an additional tie, which made us be able to go back and look at our seismic more accurately up there.

Q. Is there anything about the Snyder 2, the log data, that causes changes in structure?

A. No, it was -- It came right in as expected also.

Q. All right. When we look at Exhibit 3, your isopach today -- the May, 1995, map -- the isopach map is different than the one you used in January, isn't it?

A. Yes, as would be expected after getting more well control.

Q. Within the confines of the Hamilton tract, Hamilton's is Tract Number 1?

A. Yes, sir.

Q. That's the one where Phillips has its interest. There were no new wells drilled in the Hamilton tract, were there?

A. No, there were not.

Q. All right. And when we look at the isopach map from January and compare it to your isopach map, they appear to be the same, insofar as it covers the Hamilton tract?

A. That is correct.

Q. You didn't make any changes on the Hamilton tract?

A. Not under my maps.

Q. Okay. When we go back to the November 10th, 1994, map, isopach, from Snyder Exhibit 1 --

A. Uh-huh.

Q. -- and look at that isopach, there have been no changes in the distribution of the isopach with regards to the Hamilton tract, have there?

A. Not very much. I can't see much.

Q. They appear to me to be the same. You're the expert. Are they the same?

A. They look like they're close to the same.

Q. When we look at the hydrocarbon pore volume map from November of 1994, which is attached to Snyder Exhibit 1, and compare it to the Exhibit 9, which you introduced today --

A. Okay.

A. Have you got the two?

A. I don't have Exhibit 9.

Q. Do you see with regards to the Hamilton tract going back to November of 1994?

A. Uh-huh.

Q. When we get to May of 1995, as to the Hamilton tract --

A. Uh-huh.

Q. -- you have not changed the structure map, you have not changed the isopach. But look at the pore volume map. Substantially changed, is it not, Mr. Crow?

A. There -- we've added -- There has been some hydrocarbon pore feet added in the north half of the southeast quarter.

Q. How much hydrocarbon pore volume was added to the Hamilton tract between November of 1994 and May of 1995?

A. I don't have those numbers in front of me.

Q. If you look at the last attachment to Snyder Exhibit 1, there's a spreadsheet on there?

A. Uh-huh.

Q. If you'll turn the spreadsheet, find the Hamilton tract.

A. Uh-huh.

Q. You down and find the row that says "original oil in place" and read over to the Hamilton tract -- This is MBO, so you're --

A. You want the original oil in place calculated at that time?

Q. Yes, sir.

A. 2,558,400 barrels. Is that the number you're looking at?

Q. Yeah, you've got 2.56 million barrels of oil for the Hamilton tract in November.

A. Uh-huh.

Q. And then when we look at your Exhibit 9A and turn over and look at Tract 1 --

A. Uh-huh.

Q. -- the 2.56 million now goes to 3.6 million?

A. Yes.

Q. And the reason for that increase is that pore volume has been added in the hydrocarbon pore volume map?

A. Hydrocarbon pore volume has been added in the southeast quarter of that section. And we have the isopach. It may not indicate it, but it was decided that it was thicker in there, than what had originally been believed.

Q. Who decided it was thicker?

A. All the geophysicists going back and interpreting and looking at all the data after Phillips had had an opportunity -- When the first proposal came around, Phillips had not had an opportunity to review the 3-D data.

And so after they reviewed the data and came back and we had a long discussion and they proposed some ideas of what they thought was going on in there, that we agreed after some long discussions that they were -- you know, they had an accurate representation. And we came to agreement with them that there probably was more pore feet in there.

Q. Where on chronology did that discussion and change occur?

A. I want to say -- I'd have -- Let me look here. I think it was -- February of 1995.

Q. When you look at the chronology, look at entry number 11 on page 2. It indicates that you've met with Phillips in Odessa, discussed pressure maintenance and possible tract-participation formulas?

A. Yes, we had. But they at that time hadn't looked at the data, the 3-D data.

Q. You're adding pore volume to their tract based upon 3-D seismic data?

A. We interpreted the reef to be thicker in there than we originally thought, yes.

Q. Isn't the best indication of pore volume porosity calculations taken from log data for wells within that tract?

A. That would be more accurate, but you don't have a well in every 40 here, so you have to use some interpretation.

Q. Was there any other consideration passed between Gillespie and Phillips with regards to their participation in the unit, other than adding pore volume to the Hamilton tract in which they had an interest?

A. In what way? What do you mean?

Q. Well, consideration for paying for wellbores, any other deals involved in persuading Phillips to participate in the unit?

A. No, we just came, and once all of us got our heads together and agreed on one interpretation, we mapped it and came up with those numbers.

Q. Does Gillespie have an interest in the Hamilton tract?

A. Yes.

Q. Do you have a personal interest in that tract?

A. I have an overriding royalty interest.

Q. Did anyone for -- on behalf of Gillespie do any reservoir engineering work with regards to determining original oil in place?

A. Yes.

Q. Who did that work?

A. Mr. John McDermett.

Q. I'm sorry?

A. Mr. John McDermett. He's a consulting reservoir engineer.

Q. Are any of the proposed witnesses to be called today an engineering witness that did any material balance or volumetric calculations?

A. We have not at this time proposed to have him as a witness.

Q. Do you know, based upon your pore volume map, Exhibit Number 9, what is the original oil in place number that corresponds to that map?

A. Yes, I do.

Q. What is it?

A. Are you talking about the volumetric original in place for the pool?

Q. Yes, sir.

A. It's 11 million, nine hundred and ninety-something thousand. Just under 12 million barrels.

Q. 11.9 million is calculated volumetrically as the oil in place if we use Exhibit 9?

A. Correct.

Q. Who did that work?

A. The hydrocarbon pore feet were calculated by Ralph Nelson.

Q. Who did the engineering work to validate that hydrocarbon pore volume amount?

A. Mr. McDermett. I mean, we've all validated. Once we get the feet, the math is a pretty standard formula.

Q. All right. So you have calculated volumetrically 11.9 million barrels of oil in place?

A. Uh-huh.

Q. Now, has a reservoir engineer taken pressure and production data --

A. Yes.

Q. -- and plotted that to determine what he would tell you to be the original oil in place?

A. Yes, he has.

Q. And has he taken that information and tried to balance it with the volume calculated by Mr. Nelson?

A. Yes.

Q. Who did the engineering work?

A. Mr. John McDermett.

Q. All right. Anybody else, to your knowledge?

A. I don't know if Dalen had an engineer looking at it or not.

Q. Do you know what the oil in place is from the material balance calculation?

A. I believe he calculated just under 14 million barrels.

Q. 14 million, okay. Let's go back to Exhibit 9A, Mr. Crow, and take a look at the formula. The participation formula, who developed this one?

A. It was developed jointly by Dalen and Gillespie, and then kind of reworked with Phillips, and so the three of us agreed upon this.

Q. All right. Let's talk about the concept under the formula. Value A is the volumetric original oil in place in the unit, using these values?

A. Uh-huh.

Q. And so you get an original oil in place for the unit?

A. Yes.

Q. B is -- I didn't say that right. A is the tract's oil in place --

A. Correct.

Q. -- within the unit?

A. Excuse me. Yeah, I thought that's what you said. Yes, it's the tract's --

Q. A is --

A. -- calculated oil in place.

Q. That's right. Each tract has got an A value?

A. Yes.

Q. And that A value is its original oil in place?

A. Yes.

Q. The B value is that tract's oil recovery as of a particular date?

A. Correct.

Q. And so each tract, if it had the benefit of a well, would have a cumulative oil number?

A. Yes.

Q. The end result of the calculation is that if a tract has a well with cumulative oil production, it is going to receive less of the remaining oil in the reservoir because it's already had some of its share --

A. That is correct.

Q. -- than a tract that did not have a well --

A. That is correct.

Q. -- or has lesser cumulative oil production?

A. Correct.

Q. All right. So when we get down to C, we're looking at unit total original oil in place, from which we subtract total unit cumulative oil production?

A. Uh-huh.

Q. C minus D is going to give us remaining oil in place as of a particular date?

A. For the pool, yes.

Q. For the pool within the unit?

A. Yes.

Q. And so the concept, as I understand it, is that if there is a well in a tract that has a large current cum, it is going to receive less of the remaining recoverable oil because it's already had a benefit?

A. Correct.

Q. Correspondingly, for a tract that has either none or smaller cumulative oil production for its tract, for the remaining recoverable oil, it's going to get a larger percentage; is that not true?

A. That's in essence true. The formula is designed to give everybody credit for their original oil in place, and if you've produced some of that, it's subtracted out, yes.

Q. And it is to do just that, it is to compensate those tracts that have oil in place and low cums, to give them a chance, then, to have equity among all tracts?

A. Correct.

Q. At some point in time under this concept, the formula should balance or equalize, should it not?

A. It should, I would think.

Q. And so that at some point in time, for the remaining recoverable oil, everybody is then in an equal percentage of that remaining oil recovery?

A. Say that again. I don't quite follow what you're saying.

Q. Well, when you compare tract to tract, it has a given pore volume value, which is integrated into the formula?

A. Uh-huh.

Q. But over time, the fact that a tract had a large cum of recoverable oil prior to November 1st of 1994, its share of remaining future oil is reduced --
A. Uh-huh.
Q. -- while the other tract is increased?
A. Uh-huh.
Q. At some point in time, those are going to equalize --
A. Right.
Q. -- in terms of withdrawals?
A. Right.
Q. So once there's that level playing field, after that, everyone else is going to get their proportionate share per tract of remaining oil?
A. That sounds --
Q. That's the concept, is it not?
A. That's the concept, yes.
MR. KELLAHIN: All right. Mr. Examiner, I wonder if we might have a break. I can talk to my experts and perhaps I can shorten the remaining questions I have for Mr. Crow and we can go on to another witness.
EXAMINER CATANACH: Okay, let's take a five-minute, ten-minute.
(Thereupon, a recess was taken at 9:35 a.m.)
(The following proceedings had at 9:48 a.m.)

EXAMINER CATANACH: Ready, Tom?

MR. KELLAHIN: Yes, sir.

Q. (By Mr. Kellahin) Mr. Crow, if you go back to Exhibit 4, which is the structure map for your presentation today --

A. Yes, sir.

Q. -- I'm still unclear about how the 3-D seismic work was integrated.

Let me ask you, does this display we're looking at, Exhibit 4, include an integration of 3-D seismic information to help pick structure?

A. Yes, the structural interpretation has used 3-D to help aid interpretation, yes, sir.

Q. All right.

A. But all that was done by Mr. Scolman, and I think you really need to direct most of your seismic questions to him.

Q. When we look at the isopach that you prepared, Exhibit Number 4 --

A. Uh-huh.

Q. -- now, you've told me you have used the 3-D in a way to help you find porosity, if I understood it correctly?

A. To determine where it starts and stops.

Q. Yes, sir.

A. That's it, yes. I don't try to determine -- use it to determine thickness. Dave and the other geo- -- I'm not a geophysicist. They do that.

Q. All right. When I look at this isopach, then, what you've attempted to do is use that 3-D seismic to tell you where the reservoir pinches out, and you've done that without regard to structure?

A. Yes, sir.

Q. And when you get to that 3-D seismic work, you're looking for values on that data, and the value has got to be a porosity value, doesn't it?

A. Repeat that again.

Q. Yes, sir. When you're looking to see if the reservoir pinches out --

A. Uh-huh.

Q. -- at 12,000 feet, whatever it is, you're looking to find some point on that 3-D seismic information where you no longer have a reservoir?

A. That's what you're trying to do, yes.

Q. All right. That little squiggle, that little signature indicator, correspondingly, can be an indicator of porosity?

A. It might be. It's what we think is an indication of the mound. Whether there's porosity in it or not, that's -- You're asking a lot of questions that need to be directed to the geophysicist.

Q. Let me go back to the transcript in January, Mr. Crow. On page 30 you and I had this discussion. I asked you how you determine with 3-D seismic information the northern boundary, and the question was, "How did that help you determine where that zero line was?"

A. Uh-huh.

Q. Your answer was, "With seismic data, we feel we can depict the reef and see the actual porosity, and we attempt as best we can to follow that porosity signature out until it pinches out, and that was where we determined the zero line was."

A. That's a correct statement.

Q. All right. In January, I've got a zero line on your isopach that is based upon a northern boundary that has integrated this 3-D concept of porosity pinchout, hasn't it?

A. State that again, please.

Q. Yes, sir. On the January map, you've got a porosity value with a zero line on it. See it?

A. On the January map?

Q. It's my Exhibit 3.

A. Okay, uh-huh.

Q. Okay?

A. Uh-huh.

Q. When you compare it to Exhibit 9 -- I'm sorry, Exhibit -- What we're doing here, or what you are doing is, the zero line integrates not only log information, but this 3-D seismic concept where you're determining at a point in the reservoir where you don't have porosity anymore?

A. Correct.

Q. Okay. You went on to say -- Here was the question: "You can use the 3-D seismic information to tell you when you're low enough on the structure, [or] you're beyond the porosity that will contribute to production in the reservoir?"

We can use it for either thing, can't we?

A. To determine if you're off structure or --

Q. Yeah.

A. Sure.

Q. Okay. You say, "Yes, sir." You say, "The porosity, though, will pinch out in all directions, regardless of structure. But you can, from the seismic, determine the porosity pinchout and structural position, yes, sir."

And the question was, "Another geologist is not going to quibble with you about how that was done?"

And your answer is, "It's -- When you get into seismic, it is interpretive, and three different geophysicists might have two or three different interpretations."

A. That's true. I mean, it is interpretive.

Q. All right.

A. In this case, all three had pretty much the same interpretation.

Q. Okay. When we get to the oil-water contact, the minus 7617 --

A. Uh-huh.

Q. -- okay? Is the oil-water contact -- It should follow structure, should it not?

A. Correct.

Q. There's nothing else that's going to happen. If you find that oil-water contact at minus 7617, we ought to be able to take the structure map, follow that line all the way around, and it will conform to the structural interpretation as to that point, won't it?

A. Correct.

Q. Okay. The well locations that you've plotted on your Exhibits 3 and 4 for each of these wells --

A. Uh-huh.

Q. -- are they taken off of the completion reports, the Division form C-105s, as to the exact location of these wells?

A. Are you talking -- Are you asking about the Klein and the Snyder well?

Q. I'm asking about any of these wells.
A. Are they spotted exactly as reported?
Q. Yes, sir, that's what I'm asking.
A. All but one of them.
Q. All right, let's make it easy. Let's go to Exhibit Number 4. I'm sorry, let's try 3, that's the one I have in front of me. Exhibit 3 is the isopach.
A. Uh-huh.
Q. If I were to take the well spots for each of these wells and compare it to the C-105s that you signed and filed on behalf of Gillespie for each of these wells, am I going to be at the location where you've put the black dot on Exhibit Number 3?
A. Is C-105 the completion reports?
Q. Completion reports.
A. Yes. Except we found out at a later date the Hamilton 1 had been mis-staked, and it's actually a few hundred feet east of where it was reported to be when it was staked. It was mis-staked by --
Q. The Hamilton 1?
A. The Hamilton 1.
Q. When we look at the Hamilton 1, is that the only well that is mis-described, then, on the C-105?
A. That is the only one I'm aware of, yes.
Q. When we look at the Hamilton 1, as you have

spotted it on Exhibit Number 3 --

A. Uh-huh.

Q. -- does that represent where it's reported or where it actually is?

A. Where it actually is.

Q. And where is it actually? Do you remember the footage?

A. I believe it turned out to be 330 feet east of where it was staked. Because of the offset in the sections along that township line, they staked off of the wrong corner.

Q. I see that there's an offset as we move into the next township, and they missed that marker?

A. They staked off the wrong corner.

Q. All right. So as reported, it's going to be 330 feet farther west?

A. Yes, approximately.

Q. All right. Have you sought to correct that in the records on the well before the OCD on that particular item?

A. No, we have not.

Q. As to all the rest of them, though, they're properly reported as to location?

A. Yes, sir, as far as I know.

MR. KELLAHIN: Thank you, Mr. Examiner, I have nothing else.

REDIRECT EXAMINATION

BY MR. BRUCE:

Q. Mr. Crow, if you'd take Snyder Ranches Exhibit 1 and your current isopach -- I believe that's Exhibit 3 --

A. Uh-huh. Yes, sir.

Q. -- so go to the third page of Snyder Ranches Exhibit 1.

At the time this map was prepared, the Snyder Ranches Number 2 well had not been drilled, right?

A. That is correct.

Q. Now, if you had -- Under the terms of the Snyder Ranches lease, you were obligated to commence another well, a second well, in the Snyder Ranches lease by a certain date in 1995; is that correct?

A. Yes, by mid-March.

Q. If you had unitized before that date, then you wouldn't have had to do that?

A. Correct, I wouldn't have had to drill that well.

Q. But you did receive a request from Mr. Snyder to drill that additional well?

A. I don't remember receiving one in writing, but I got a demand on the phone, yes.

Q. Over the past -- any number of months, you've been -- without Mr. Kellahin and I intervening, you've been

in phone touch, phone contact with Mr. Snyder, haven't you?
A. Yes.
Q. I mean, excuse me, Mr. Squires?
A. Mr. Squires, yes.
Q. Now, when you originally drilled that well, based upon the original isopach map, it looked like there was -- You originally thought there was going to be closer to -- maybe 50 feet?
A. We had hoped there might be 50 feet in that well, yes.
Q. What did it turn out to be?
A. It actually had 36 feet of 3-percent or greater porosity.
Q. So there was a substantially lesser amount of net porosity, then, at that location than you had originally thought?
A. Yes, which resulted in a calculation of less hydrocarbon pore feet.
Q. And that resulted in a decrease in the value attributed to the Snyder Ranches tract?
A. Yes, it did.
Q. Now, on the participation formula, Exhibit 9A, the basic formula itself, the A minus B divided by C minus D, that didn't change over the past nine months?
A. No, it did not.

Q. Okay. What changed were the values attributed to each tract, based upon the hydrocarbon pore feet map?
A. Yes, after new well control and --
Q. And some additional production
A. -- some additional interpretation and more production.
Q. And the other item that changed is, when you drilled the Klein Number 1 well you were able to get a water sample?
A. Yes, we recovered water on the drill stem test. We were able to get a more accurate R_w. Prior to that, we had used an assumed R_w of .04. And once we analyzed the water, we found out the actual R_w was .052, which resulted in lowering the overall volumetric calculation in the pool.
It basically told us there was more water in the reservoir than we originally thought.
Q. Now, back in November or December, Gillespie and Dalen Resources made a proposal to the interest owners based upon certain tract participation factors?
A. Back in December --
Q. Yes.
A. -- did you ask me? Yes, uh-huh.
Q. Under the formula then proposed, or I should say the tract participation formulas then proposed, what was the combined working interest in the unit of Charles B.

Gillespie, Jr., Dalen Resources and you personally?

A. I don't know the exact number, but I believe it was somewhere in the range of 96, 97 percent.

Q. Okay. As you are currently --

A. 96, I think.

Q. 96? As you are currently proposing, as Gillespie-Crow, Inc., is currently proposing unitization, what is the combined working interest in the unit of Mr. Gillespie, Dalen -- now Enserch -- and you individually?

A. It's around 92 percent or so.

Q. So you -- It was decreased three or four percent --

A. Yes, yes.

Q. -- based upon the new formula or new participation, tract participation figures proposed to the OCD today?

A. Yes, it dropped.

MR. BRUCE: I don't think I have anything further, Mr. Examiner.

MR. KELLAHIN: Two follow-up questions, Mr. Examiner.

RECROSS-EXAMINATION

BY MR. KELLAHIN:

Q. The R_w is a residual water number, is it not?

A. Resistivity of the water, yes.

Q. Yes, and it is normally derived from a drill stem test, isn't it?
A. That's how you initially get your water, or even if you have a producing well, you can take a sample there and have it analyzed.
Q. And the value is .052; that's the correction number?
A. That was corrected to a depth of 11,500 feet.
Q. Did you do any of the water saturation work or calculations of that information off the log?
A. No, Ralph Nelson did them.
Q. Nelson did all that?
A. He did all the work for the hydrocarbon pore feet and the calculations.
Q. You and Mr. Bruce were talking about the results of the Snyder 2.
A. Yes, sir.
Q. When we look at the isopach on Exhibit 3, you only got 36 feet of pay?
A. That was equal to or greater than 3 percent.
Q. All right. Using the cutoff, when you actually drilled the well, you got 36 feet of pay?
A. That's what we calculated with the QLA2 program, yes.
Q. The estimate of an original target of 50 feet of

pay --

A. We had mapped -- My interpretation and map, I had hoped it might be as thick as 50 there when we had drilled it.

Q. You said you had picked all these wells, I think, after 1994?

A. Uh-huh.

Q. When you had the 3-D seismic work, all those subsequent wells were picked using 3-D seismic information?

A. That is correct.

Q. Was the original Snyder 2 well picked based upon 3-D seismic work?

A. Yes, it was.

Q. And that work would have indicated 50 feet of pay?

A. We never tried to model how thick. It just showed it was the best spot in that laydown 80 to drill.

Q. As a result of the prediction, you have mapped it, and you have mapped it to be 50 feet?

A. In the prediction, yes.

Q. Yes, sir. And that prediction included the 3-D seismic work, didn't it?

A. No. I mean, I did not use any seismic to try to determine how thick anything was.

Q. You were picking these locations, though, based upon 3-D seismic work?

A. Based upon the signature, the character of the signature, where it appears to be the best.

I couldn't tell you whether it's five feet, ten feet, fifty feet from seismic. I couldn't.

Dave and the geophysicists might be able to do that kind of thing. I can't. I'm just saying that it looked deepest there.

Q. In January, on the isopach in January, that isopach zero line included your 3-D seismic work when you're looking at the reservoir pinchout, right?

A. On which map?

Q. The January map.

A. The zero line, yes.

Q. Yes, sir. And that also included the zero line in the southeast quarter?

A. Yes, that and we used a lot of the -- extrapolated out the top of the dip off of the Earnestine 1 to the Earnestine 2 and how much it was dipping off of there and how quickly the reef was thickening, and we used well control also to pinpoint approximately where that ought to reach the edge of the reef.

Q. Do you anticipate any more wells being drilled in the unit?

A. One more well.

Q. Where will it go?
A. Somewhere in the northwest quarter. We have not determined exactly where yet.
Q. And what's the purpose of that?
A. Once we start pressure maintenance, we feel like with gravity segregation we're going to push some oil out that way; there needs to be a wellbore out there to drain that area.
Q. The concept is, we're going to put gas back into the structure at one of the highest points in the reservoir --
A. Yes.
Q. -- take that gas and inject it, and the fringe wells then become the main producing oil wells?
A. That is correct.
Q. And so you want a fringe well up in the northwest?
A. Yes, that's correct.
Q. The Snyder 2 served that purpose in the southeast quarter, didn't it?
A. It will serve that purpose.
MR. KELLAHIN: Yeah.
Thank you, Mr. Examiner.
I have nothing else.
EXAMINER CATANACH: Just a couple, Mr. Crow.

EXAMINATION

BY EXAMINER CATANACH:

Q. The revision to the pore volume was done, as I understand it, by Phillips and agreed to by your company?

A. No, it was not. I mean it was done by the geophysicists after we drilled two additional wells.

We took that data -- You really need to get Mr. Scolman up here to explain how he interpolates all that back into the seismic.

But that was -- The new well data was used. And then Phillips, after they had an opportunity for the first time to see the 3-D data, came in with us and we had, you know, discussions on what was going on and came up with an interpretation that everybody thought was very acceptable.

Q. So you used data from the two new wells and integrated it back into seismic to help you revise the map?

A. Yes.

Q. How did revising that map affect the other tracts? Did it have an effect on the other tracts?

A. Yes, certainly a few of the tracts went up, a lot of them went down, you know.

The amount of overall oil in place didn't change, other than -- very much, other than the fact that the R_w went up some. But some tracts went up and some tracts went down.

Q. Do you know how it affected the Snyder tract?
A. The Snyder tract did go down, I believe, from some -- I don't have the exact numbers, but it went down from having a tract participation of around 8 to about 6.3, or something, percent.
Q. Okay. When were those two wells drilled, the Snyder 2 and the Klein?
A. Yes, sir, the Snyder 2 was drilled -- I believe we spudded that well in February, late February of 1995, and ended up completing it in April.
We also -- That was the first well that we had actually a good-looking zone down deeper that we spent time testing. And the zone turned out to be too tight to produce, and we ended up completing.
And then the Klein well was drilled immediately -- We just moved the rig over, and so we spudded it in March, and I believe it was completed right at the end of March or...
Q. This whole reservoir is in communication with -- This whole area is in communication, this whole structure?
A. We believe it is. When you take bottomhole pressure tests, they build up to approximately the same pressure.
Q. And the southern limit of the boundary, the southern -- was determined how, again?

A. That -- Really, there's not any more well control, of deep well control to the south for several miles. So it was picked off of 3-D.

And that reef on the back side is so steep that it's very distinguishable where that abruptly drops off.

EXAMINER CATANACH: That's all I have of the witness, Mr. Bruce.

MR. BRUCE: I have nothing further of this witness.

EXAMINER CATANACH: This witness may be excused.

KEVIN WIDNER,

the witness herein, after having been first duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Will you please state your name for the record?

A. Kevin Widner, Midland, Texas.

Q. Who do you work for and in what capacity?

A. I'm the secretary/treasurer for Gillespie-Crow, Incorporated, and the production manager for Charles Gillespie, Jr.

Q. By profession or by schooling what are you?

A. Petroleum engineer.

Q. Have you previously testified before the Division as a petroleum engineer?

A. Yes, I have.

Q. And were your credentials accepted as a matter of record?

A. Yes, they were.

Q. And are you familiar with the engineering matters pertaining to the proposed unit in the West Lovington-Strawn Pool?

A. Yes.

MR. BRUCE: Mr. Examiner, I tender Mr. Widner as an expert petroleum engineer.

EXAMINER CATANACH: Mr. Widner is so qualified.

Q. (By Mr. Bruce) Mr. Widner, would you briefly describe why you're seeking to institute a pressure-maintenance project? And I'd refer you to your package of information marked Exhibit 12.

A. Exhibit 12 is a package of information which summarizes the discovery and the development of the proposed pool, which Mr. Crow has already discussed. Within the package is a chronological history of the pressure depletion of the reservoir.

The original bottomhole pressure was 4392 and the current bottomhole pressure is 3363. The bubble-point pressure was calculated as 4130.d

The reservoir was initially undersaturated. But as our bottomhole pressure indicates, the reservoir now is in a saturated state, which means that any slight reduction in reservoir pressure causes gas to be released from solution.

This free gas that breaks out of solution is not mobile and does not flow into the wellbore. Thus, as the reservoir pressure is depleted, gas continues to break out of solution, increasing the gas saturation in the reservoir until the critical gas saturation is reached.

Prior to reaching critical gas saturation, the producing gas-oil ratio will decrease because the gas is not mobile yet.

However, once this critical gas saturation is reached, the gas becomes mobile and flows into the wellbore. At this time the producing gas-oil ratios will increase very rapidly, reducing the oil rate and depleting the reservoir of its main energy source, which greatly reduces the ultimate recovery of the reservoir. This type of production characteristic has been noted in various other Strawn reservoirs in this general area.

It is our intent to inject gas into the top of the reservoir and create a gas cap in order to stop the reservoir depletion prior to this critical gas saturation being reached.

Q. Is this portion of the pool that you seek to unitize suitable for unitization and pressure maintenance?

A. Yes, it is.

Q. Referring to your Exhibit 13, how did you project production for the pool under your proposed pressure maintenance division?

A. Exhibit 13 is a production projection for the pool under a pressure-maintenance program.

As long as we are able to control the producing gas-oil ratios, the oil and gas producing rates will be held constant. Once the producing gas-oil ratios begin to increase, the oil rate will decline rapidly until the oil volume is depleted.

At some point during the project, it will become uneconomical to inject gas due to low oil-producing rates. At this time, the field will be blown down.

Q. What is Exhibit 14?

A. Exhibit 14 is a plat of the proposed unit area, showing one injection well and ten producing wells.

Q. What will be the plan of operations for the unit? I refer to your Exhibit 15.

A. The plan of operation will be to turn the Speight Fee Number 1 into an injection well, isolating the upper perforations for the injection interval.

The necessary compression and gathering lines will be installed to deliver injection gas to the well. The lower 10 to 15 feet of perforations in the producing wells will be isolated for the producing interval.

Initial production rates will be set at approximately 175 barrels a day per well. It is planned to inject a total volume of produced and purchased make-up gas that will equal approximately 5000 MCF a day.

The reservoir pressure will be monitored, and the producing and gas injection rates will be adjusted to maintain the reservoir producing pressure. The field producing GOR will be controlled by shutting in or working over the high-producing-GOR wells.

Q. What are the wells in the unit currently producing?

A. Each well right now is currently choked back to a production rate of approximately 100 barrels of oil per day. Once the gas injection begins, the producing rate will be increased to about 175 barrels a day, which will be adjusted depending on the performance of the reservoir.

Q. Okay. And as Mr. Crow indicated, there is an additional development well planned?

A. Yes, there's one additional development well in the northwest portion of the unit.

Q. What additional facilities are needed for this project?

A. Gillespie-Crow, Incorporated will not have to install any additional facilities for the project.

A gas-gathering and -processing agreement has been made between Gillespie-Crow, Incorporated, and another party by which there will be no capital expenditure for Gillespie-Crow, Incorporated, for additional facilities, gathering lines or compression to initiate the project.

Q. Well then, go into the economics of it a little bit. What initial cost will there be for Gillespie-Crow to initiate that?

A. There will be very little capital cost to initiate the project. It is estimated that it will cost a total of approximately $50,000 to mechanically isolate the upper perforations in the injection well and the lower perforations in the producing wells.

The only expenditure during the project will be purchasing make-up gas for injection. It is our estimate that even after purchasing make-up gas, the project would net an additional $4 million to the working interest owners and generate over $2 million to the royalty owners.

Q. And what is Exhibit 16? Does it show some of that proposed economics for that --

A. Yes, that was Exhibit 16, yes.

Q. In your opinion, will the oil and gas recovered by the unit operations exceed unit costs, plus a reasonable profit?

A. Yes, it will.

Q. What is the estimated life of the project?
A. Fifteen years.
Q. Is it prudent to apply an enhanced recovery program to this pool at this time?
A. Yes, it is.
Q. And is the pressure maintenance project economically and technically feasible at this time?
A. Yes.
Q. Will pressure maintenance operations prevent waste?
A. Yes.
Q. And will the operations result in the increased recovery of substantially more hydrocarbons from the pool than would otherwise be recovered?
A. Yes, it will.
Q. In your opinion, is the unitized management, operation and development of this pool necessary in order to effectively carry on pressure maintenance operations?
A. Yes, it is.
Q. Will the unitized operations increase ultimate recovery of oil from the pool?
A. Yes, it will.
Q. And will your proposed operations benefit not only the working interest owners but the royalty owners in the pool?

A. Yes, it will.

Q. Let's move on to the injection part of the Application. Would you identify Exhibit 17 for the Examiner?

A. Exhibit 17 is the form C-108 and its attachments, which was submitted with our Application.

Q. Would you please discuss briefly the proposed injection well and how it will be reworked?

A. The porosity in the Speight Fee Number 1 is structurally highest in the field. When it was completed, the entire pay interval was perforated.

To ensure that gas is going to be injected in the top of the reservoir, it is planned to set a cast-iron bridge plug 10 to 15 feet below the top of the porosity, isolating the upper set of perforations. A packer will be set about 150 feet above the perforations, and the gas will be injected down 2 7/8 tubing.

Q. How many wells are there in the area of review?

A. There are five unit wells and the Amerind West State Number 1 in Section 2 in the area of review. A map in the C-108 Application shows these wells.

Schematics of the wells are also included in the C-108 application. All wells in the area of review have three casing strings.

The surface casing is set at approximately 400 feet and cemented to surface in all wells.

The intermediate string, or 8 5/8 casing string, is set at 4750 and cemented to around 1900 feet, and in some cases cemented to surface.

The production strings are set at approximately 11,800 feet and cemented to around 9000 feet.

There are no plugged and abandoned wells in the area of review. All wells in the area of review are less than three years old, and all but one were drilled by Charles Gillespie.

Q. Okay. To the best of your knowledge, is the mechanical integrity of all wells in the area of review sufficient to conduct injection operations?

A. Yes, there will be no migration of injection gas to other zones.

Q. And what will the injection pressure be?

A. The surface injection pressure is estimated at 2700 pounds.

Q. And is the injected gas compatible with formation gas?

A. Yes, it is. All injection gas will come from a high-pressure natural gas pipeline five miles west of the field. This gas is pipeline-quality and has no impurities.

Q. Are there any water wells in the area of the proposed injection well?

A. Yes, the wells are shown on the map included in the C-108 application. The wells produce at a depth from 100 to 200 feet, and all oil and gas wells within the area of review have surface casing set to a depth of at least 375 feet and cemented to surface.

Q. And the information on the water wells was obtained -- Was it obtained from the State Engineer as well as your field operatives?

A. Yes, it was.

Q. Are there any faults or hydrologic connections between the freshwater sources and the injection formation?

A. No, there is not.

Q. What is Gillespie-Crow, Inc., requesting for the initial project area for this unit?

A. It is requested that the project area, pursuant to Division Rule 701, encompass the entire unit area.

Q. And what project allowable do you request?

A. It's requested that the allowable be set at 445 barrels of oil per day per well, or 4895 barrels a day for the unit.

Q. And was notice of the form C-108 sent to the necessary parties as required by Rule 701 and other Division rules?

A. Yes, it was.

Q. And other than Mr. Gillespie, the only offset was

Amerind Oil Company; is that correct?

A. Yes, uh-huh.

Q. And then the surface owner is TCH Ranches, Inc.?

A. Yes.

Q. And is Exhibit 18 my affidavit of notice regarding the mailing of the C-108?

A. Yes, it is.

Q. In your opinion, will the granting of this Application be in the interest of conservation, the prevention of waste and the protection of correlative rights?

A. Yes.

Q. And were Exhibits 12 through 17 prepared by you or under your direction or compiled from company records?

A. Yes, they were.

MR. BRUCE: Mr. Examiner, I'd move the admission of Gillespie Exhibits 12 through 18 at this time.

EXAMINER CATANACH: Exhibits 12 through 18 will be admitted as evidence.

Mr. Kellahin?

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Widner, do you see any pressure gradients in the reservoir?

A. From our dip-in test, we have seen some pressure gradients in the reservoir, within each wellbore.

Q. Are they significant differences between those pressures to cause you concern that you have any restrictions or barriers to fluid flow in the reservoir?

A. No, they're not.

Q. From an engineering perspective, then, it is feasible, in your opinion, to have this upstructure injection well as an energy source, if you will?

A. Yes.

Q. To help move the oil to the ring of outer producing oil wells that are lower on structure?

A. Yes, it does.

Q. So you don't see any reservoir data to indicate that there are any kind of barriers to the movement or migration of either the gas or the oil?

A. No, I do not.

MR. KELLAHIN: No further questions. Thank you.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Widner, is this single injection well -- that's going to be the only injection well used in the project?

A. Yes, it is.

Q. Do you believe that's sufficient to accomplish what you intend to do?

A. Yes, we do, uh-huh, at the producing rates that we estimate, the reduced production rates.

Q. How did you determine the injection pressure to be utilized in the well?

A. It was just calculated with the basic friction calculation numbers. Most of that pressure is due to the friction between the 2 7/8 tubing in the smaller tubing string and the high rate of 5 million a day being injected down the 2-7/8-inch tubing.

Q. Is that pressure below fracture pressure for the formation?

A. Yes, it is.

Q. Do you know what that is?

A. No, I really don't. The bottomhole injection pressure shouldn't be much more than 500 pounds or so above the bottomhole pressure.

Q. What is the allowable based on? Is that the current allowable for each well?

A. Yes, sir, the current allowable or top allowable wells. And it is 445 barrels a day, per well.

Q. And what is the current GOR for this pool?

A. The pool GOR, I believe, is approximately 1800. I would have to look at my cumulative --

Q. Okay, do you know what the statewide rule for that is? Is that a 2000 to 1?

A. It's 2000, yes.

MR. BRUCE: Mr. Examiner, the only pool rules that apply are 80-acre spacing at this time.

Q. (By Examiner Catanach) You're not seeking any kind of relief for the current GOR; is that correct?

A. Correct.

Q. It's your opinion that injection into this one well will affect producing characteristics of all wells in the pool?

A. Yes, it will.

EXAMINER CATANACH: I have nothing further, Mr. Bruce.

MR. KELLAHIN: A couple of follow-up questions.

FURTHER EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Widner, if -- It's a single-well gas injection concept?

A. Yes, sir.

Q. Under that scheme, you forecasted for us back in January that while you couldn't accurately predict it, you were hoping anywhere between a 40- and a 60-percent recovery of total reservoir oil within the unit; wasn't that correct?

A. That was -- It was hoped. I mean, that's not what we're expecting, of course. It's hoped we could get higher if possible. But at that time we were hoping for that range.

Q. Did you do any material balance work? Mr. Crow mentioned that someone had calculated on material balance that you had about 14 million barrels of oil in place?

A. That's correct. I did not do material balance calculations.

Q. But the number you've been working with is 14 million barrels of oil in place?

A. For -- For what? What purpose?

Q. For any purpose.

A. We've been using volumetric numbers also.

Q. But you didn't do any of that work in validating the isopachs or the hydrocarbon pore volume data?

A. No, I did not.

MR. KELLAHIN: Thank you, Mr. Examiner.

EXAMINER CATANACH: The witness may be excused.

MR. BRUCE: Call Mr. Nelson.

RALPH NELSON,

the witness herein, after having been first duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Would you please state your name for the record?

A. Ralph Nelson.

Q. Who do you work for and in what capacity?
A. Dalen Resources, now Enserch Exploration, as a geologist.
Q. Have you previously testified before the Division?
A. Yes, I have.
Q. And were your credentials as an expert petroleum geologist accepted as a matter of record?
A. Yes, they were.
Q. And are you familiar with the geology involved in the West Lovington-Strawn Pool?
A. Yes.
MR. BRUCE: Mr. Examiner, I tender Mr. Nelson as an expert petroleum geologist.
EXAMINER CATANACH: Mr. Nelson is so qualified.
Q. (By Mr. Bruce) Mr. Nelson, would you please briefly discuss your involvement in interpreting the geology in this pool?
A. As project geologist for Dalen, I made structure maps and isopach maps, correlated logs, performed net cutoff numbers, calculations on the logs.
In a net cutoff, we compared core porosity to log porosity. And the resulted comparison, we found that 85 percent of density porosity equalled -- was the good match between the core and the logs.

I also performed the detailed log analysis used to construct the HPV map.

Q. Okay. Specifically for the analysis and the log data, what went into that?

A. Well, we took the digital log data, provided -- that we obtained from the logging companies, as well as several wells we had to digitize. We entered those -- that digital data into the computer and used the QLA2 logging analysis program to calculate the HPV number. We used the Permian Basin standard water saturation formula. With that, we calculated oil percentages, oil saturations. The saturations then were multiplied by the net porosity values, every half foot, and added. Then this number, then, equaled or represented the hydrocarbon pore feet at each wellbore.

These values were then incorporated into the geophysical data to generate the HPV map, with Mr. Scolman.

Q. That's what was previously marked Exhibit 9; is that correct?

A. Yes.

Q. Okay. So both you and Mr. Scolman participated in preparing that map?

A. Yes.

Q. In your opinion, does that map fairly reflect the hydrocarbon pore volume under each unit -- under each tract in the proposed unit?

A. Yes.

Q. And was Exhibit 9 prepared by you or under your direction?

A. Yes, it was.

Q. In your opinion, is the granting of this Application -- these Applications, I should say -- based on the interests of conservation and the prevention of waste?

A. Yes, it is.

MR. BRUCE: Mr. Examiner, at this time -- we did not previously move it -- I would move the admission of Exhibit Number 9.

EXAMINER CATANACH: Exhibit Number 9 will be admitted as evidence.

MR. KELLAHIN: Me again, huh?

EXAMINER CATANACH: You again.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Okay. Mr. Nelson, describe for me the reservoir lithology.

A. It's an algal limestone, phylloid algal limestone.

Q. Describe for me how they were deposited.

A. Deposited in the Pennsylvanian sea at or near way face and subareally exposed, creating the leaching that enhanced the reservoir porosity.

Q. When we look at -- this is a -- Is it a carbonate reservoir, carbonate algal mound?

A. Right, limestone.

Q. When you look a the Strawn limestone, is it deposited on top of the Strawn McWright?

A. Yes, it is.

Q. You're familiar with that term?

A. Yes.

Q. So when you look throughout this reservoir, you look at a depositional environment, can you readily identify a marker that would be consistently recognized as the top of the Strawn McWright?

A. Yes. Yes, there's a hot streak that sometimes confuses that slightly, but still you pick the top of the McWright within a range of a few feet.

Q. The production or the producing portion of the Strawn formation is contained in the limestone above the McWright?

A. That is correct.

Q. And that will have a varying degree of thickness, based upon how these algae or algal accumulations were distributed on top of the McWright?

A. Correct.

Q. How does the algal mound compare to or differ from simply a reef deposit, if you will?

A. With a phylloid algal mound is a baffling agent. The phylloid algae traps sediment as baffling agents, sea grass.

When you mention the word "reef", that has a wide range of definitions. This is one type of reef.

Q. Have you studied the core? Is there core data available out of any of these wells?

A. There's core data available on two wells.

Q. Have you physically looked at the cores?

A. I -- No, I have not, physically.

Q. You've looked at a core analysis prepared by someone else?

A. I've looked at photographs and core analysis, yes.

Q. Did you observe the porosity in the cores?

A. I did, yes.

Q. And what did you see?

A. It's vuggy porosity.

Q. Where do you believe the porosity is in the producing zones? You know, is this -- The porosity system, if you will, is it simply contained within these pockets of porosity? Is there a secondary or a primary porosity component to the reservoir, any of that?

A. I believe it's all secondary porosity.

Q. Okay. When you look at the log data --
A. Uh-huh.
Q. -- you did the log analysis on the wells that generated the hydrocarbon pore volume map?
A. Yes.
Q. That represents all your work, Mr. Nelson?
A. Yes. Mr. Scolman did help or assist in that, but yes, I did.
Q. Part of the process to get the hydrocarbon pore volume map is to take the thickness, this net thickness, whatever number you end up with, times a porosity value, right?
A. Well, the way that we did it in this case is, we calculated the oil saturation every half foot, multiplied it by that half-foot porosity value and then summed the numbers.
Q. All right. Part of that calculation includes an analysis of water saturation, doesn't it?
A. That's correct.
Q. All right. And there are three parts to that water saturation analysis, aren't there?
A. Would -- Yes.
Q. You have an R_w value?
A. R_w, R_t and porosity.
Q. All right. The R_w value was the one that Mr.

Crow told us, the .052?

A. Yes.

Q. All right. Then you have an R_t value, which is the true resistivity; is that not what that means?

A. The R_t is the resistivity in this case measured by the deep lateral curve.

Q. All right, that's what I want to ask you. How did you find the R_t value that was used in the log analysis?

A. Off the digital log data.

Q. And you looked at the far right portion of that log and you got the DLL, whatever that is, the deepest lateral reading on that log?

A. That's correct.

Q. Why did you choose to do that?

A. That should represent the truest resistivity, the deepest resistivity, measured in that log.

Q. All right. The other part of the formula has to do with picking a porosity value?

A. Yes.

Q. All right. How do you do that?

A. As I previously described. We used the value of the -- compared the cross-plotted -- actually compared the cross-plotted density neutron porosity to the core porosity and found our best match was not a true cross-porosity but

it was 85 percent of density porosity.
That's when we compared, foot by foot, the core data to the log data.
Q. Do you have available to you the log on the Hamilton Federal Number 3 well?
A. Off the cross-section, I don't have that. But maybe we can get it off the cross-section.
Q. I think it's on one of the cross-sections. If we might have a moment, let's see if we can find that.
Okay, we'll talk about where you pick density, but if I understood correctly, you took density and you multiplied it by .85?
A. That's correct.
Q. That would reduce the porosity value?
A. That's correct.
Q. Why would you reduce the porosity value, rather than simply taking the full porosity value off the log? Why the multiplier, .85?
A. Well, the -- Both logging curves, the density curve and the neutron curve, were run on limestone matrix. The fact that they don't lay on top of each other in most of the porosity zones indicates perhaps that's a function of gas.
Q. There's a gas effect?
A. There's a gas effect.

Q. What is the significance of .85, as opposed to some other multiplier?
A. That was the comparison of real rock data with the log data.
Q. When you're dealing with gas effects, then, you have a gas reservoir or an oil reservoir? I don't understand what you mean.
A. Well, we believe that to mean that the gas-oil ratio had an effect on that separation between the two curves, the higher gas-oil ratio affected that.
Q. All right. When you look at the original discovery well, the Hamilton 1 --
A. Uh-huh.
Q. -- that Hamilton 1 is producing the reservoir pressure above the bubble point, right?
A. I believe so.
Q. And that would indicate that all the gas is in solution with the oil?
A. Yes.
Q. If you looked at the log of the Hamilton 1, would you see a gas effect on that log?
A. I don't know, I'll look.
Q. Yes, sir, if you will.
A. Is it on this section?
MR. CROW: That's on cross-section B.

THE WITNESS: Okay.

Q. (By Mr. Kellahin) On the Hamilton 1, is there a gas effect on that log?

A. Yes.

Q. And that is the .85 multiplier?

A. That is the -- what we used after comparing that with the rock data, yes.

Q. Did you look at all the logs in the well and see a similar gas effect, or what you concluded was a gas effect?

A. We see that in most of the wells, as I recall.

Q. All right. On the Hamilton 3, we have that out there, I think, somewhere, the Hamilton 3. I'm interested in how -- off of what curve you have picked your porosity value.

A. The density curve there is the solid curve on the right side of the track, well track.

Q. I need to get a copy of the log. Hang on just a second.

All right, you're picking off the curve that is on the right-hand side of the log. It's the dark line?

A. The solid line, yes.

Q. The solid line, it is to the left of the dashed line?

A. Yes.

Q. All right. We need to get a copy of that to the Examiner. I don't think he's got one.

EXAMINER CATANACH: Is that on B-B?

THE WITNESS: It's on A-A. It's the one right there on the left.

Q. (By Mr. Kellahin) All right, let's go down that log and have you help me find the interval that's at 11,560, 11,561. Can you find that, Mr. Nelson?

A. Okay.

Q. If you read over on the dark line on the right, that density curve that you're looking at, what porosity percentage do you find at 11,561?

A. It looks to be almost 8 percent.

Q. Show me how you read the 8 percent. You come straight off the log header?

A. Yes, from the header. It's a minus 10 to 30 scale, with 30 being to the left.

Q. All right. Now, this logging tool had a repeat pass to it, didn't it?

A. Should have.

Q. All right, and you're looking down at the repeat portion of the log?

A. I am looking at --

Q. I don't know, I'm asking you.

A. No, we should be looking at the main pass.

Q. You're looking at the main pass?
A. Yes.
Q. All right. And you've picked 8 percent at that depth, okay?
A. Yes.
Q. You've got what? 8 percent at 11,560?
A. 11,561.
Q. Yes, sir, about there?
A. Yes.
Q. All right. What did you use in your calculation, then? There was a spreadsheet generated based upon this data.
A. We used 8 percent times .85.
Q. Do you have a copy of that spreadsheet data with you? Perhaps we can look at it at the break, then --
A. Okay.
Q. -- Mr. Nelson, to keep things going. We'll see if we've got that information.
A. Okay.
Q. And that's the system, then, you used for all these wells?
A. Yes.
Q. Okay. We're looking at that density curve on the right-hand portion of the log scale, and you're following that down and you're finding the porosity value and you're

multiplying that times the .85?

A. That's correct.

Q. Let's talk about the gas effect for a minute, Mr. Nelson. Describe for me what happens with the gas effect.

A. When you have gas effect, the neutron curve is affected by the gas, since it measures hydrogen atoms. Therefore, in a gas they're more spread out, and therefore it reads a more pessimistic porosity reading.

Q. It's going to change or alter the gas saturation portion of the calculation, isn't it, if I understand that correctly?

A. What -- I don't understand.

Q. Well, you get a lower neutron porosity based upon the gas effect, don't you?

A. That's correct.

Q. All right. And you get a higher density?

Well, let's talk about where you are in the reservoir. If you're higher in the reservoir, above the oil-water contact, what happens to the gas effect?

A. I don't know in this particular reservoir, without looking at the Speight well.

Q. Okay, and as you move down towards the oil-water contact, is there going to be a change in the gas effect?

A. I'm not sure that I could say that in this reservoir without looking at these logs.

As I look at this cross-section, I see an oil-water contact on this Hamilton 3 and I see that there's gas effect down at the bottom.

Q. Do you have the log of the Wiley well? That's the -- It's on one of these cross-sections.

A. Yes, I do.

Q. It's the one in the southeast of the northeast of 33, the Wiley well?

A. Yes, I do.

Q. Let's look at the gas effect on that well, as you move towards the oil-water contact. What do you read?

A. There's still gas effect.

Q. Now, as we move down below the oil-water contact, at what elevation do we find the oil-water contact in the Wiley well?

A. On this cross-section it's marked at 11,614 feet.

Q. Okay, let's go below that and see what happens to the gas effect.

A. There still appears to be a little gas effect. However, you do have a statistical variance in those two logging tools.

Q. What did you do about the potential gas effect in the water-leg portion of the reservoir?

A. We did not calculate a hydrocarbon pore volume at that point.

Q. Did you prepare the pore volume map that was presented to the various parties back in November and December of 1994? I had it as Snyder Exhibit Number 1, Mr. Nelson.

A. I prepared -- I did the numbers, and Mr. Scolman did the -- with my assistance, made the map, yes.

Q. Okay. Do you have a copy of that hydrocarbon pore volume map in front of you?

A. Yes, I do.

Q. All right, let's compare it to Exhibit 9, which is the one we have for today's hearing.

When we look at these values adjacent to each of the wells, that value is the value you derive from log analysis?

A. Yes.

Q. The contouring of those values as we move throughout the display has been influenced by 3-D seismic interpretations?

A. Yes.

Q. But as to each individual well, that value should be the same for either display, shouldn't it?

A. Well, no, it shouldn't. As we -- As Mr. Crow had described, we obtained a water sample on the Number 1 Klein well and we had assumed an R_w of .04 in the original calculations. And before that point in time we did not have an actual water sample. When we obtained the water sample, we re-calculated all of the numbers to reflect that correct -- new correct R_w number.

Q. All right. Other than changing the R_w to .052, are there any other changes that resulted in variances of these numbers?

A. No, should not be.

Q. Okay. So if I do a calculation or have the engineer do a calculation, .04 converted to .052, I'm going to get the same number?

A. Yes, you should.

Q. Okay. When we go to the November, 1994, hydrocarbon pore volume map, there was a method of calculation of the porosity that we've just described --

A. Yes.

Q. -- where you had an R_w, an R_t and then a porosity value?

A. Yes.

Q. Was the system that you have used to describe the Hamilton well on Exhibit 9 the same methodology that was used back in November of 1994?

A. Yes, it was.

Q. Done the same way?

A. It was done the same way.

Q. When we look at the two maps, did you make any changes in what I would call the raw data in terms of picking porosity values, thicknesses or any of the other items, other than changing the R_w number?

A. No, all we did was loaded the digital data, and the computer did the rest.

MR. KELLAHIN: Thank you, Mr. Examiner.

EXAMINER CATANACH: Anything, Mr. Bruce?

MR. BRUCE: Nothing, Mr. Examiner.

EXAMINER CATANACH: I have no questions of this witness.

MR. KELLAHIN: Subject to recall, Mr. Examiner, with Counsel's assistance, we'll ask Mr. Nelson to find that spreadsheet that Mr. Gillespie had provided to us on some of these log calculations, so subject to that, I have no more questions for Mr. Nelson.

EXAMINER CATANACH: Okay, the witness may be excused.

MR. BRUCE: Call Mr. Scolman to the stand.

DAVID A. SCOLMAN,

the witness herein, after having been first duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Would you please state your name and city of residence?

A. My name is David Scolman. I live in Plano, Texas.

Q. Who do you work for?

A. I'm a staff geophysicist. I work for Dalen Resources, which, as of June 8th, was merged with Enserch Exploration.

Q. Have you previously testified before the Division as a geophysicist?

A. Yes, I have.

Q. And were your credentials accepted as a matter of record?

A. Yes, they were.

Q. And are you familiar with geophysical matters pertaining to the West Lovington-Strawn Pool?

A. Yes, I am.

MR. BRUCE: Mr. Examiner, I would tender Mr. Scolman as an expert geophysicist.

EXAMINER CATANACH: Mr. Scolman is so qualified.

Q. (By Mr. Bruce) Introductory question, Mr. Scolman. What is Dalen's working interest in the unit?

A. 45.97 percent.

Q. So they have a substantial interest in this unit, they --

A. Yes, sir.

Q. It's a very important unit, in other words?

A. Yes, sir.

Q. Would you please discuss your involvement in interpreting the geology of the West Lovington-Strawn Pool?

A. I provided the seismic interpretation and worked to integrate that interpretation with the rest of the geological and engineering information to come up with our interpretation of the Strawn Pool.

Q. What did you do with the data?

A. I started with Ralph Nelson's interpretation, the geological and petrophysical interpretation of the wireline data and of the core data. I used that, then, to calibrate the 3-D seismic and from that calibration determined the structure of the pool and the geometry of the pool.

Q. Did you use this information to -- in assistance with Mr. Nelson, to calculate the hydrocarbon pore feet?

A. Yes, I did. We -- Prior to the drilling of the Snyder 2 and the Klein well, we looked at the time structure and signatures of the wells and compared those to the seismic data. We used area rules of thumb, essentially, as to what the time relationship is to the depth relationship.

We then used the time interpretation of the seismic data to modify our structural picture at the wellbores, the ground truth at the wellbores.

Following the drilling of the additional two wells, of the Snyder 2 and of the Klein well, we expanded our effort in the depth conversion of the seismic data. I went to a more regional picture.

I went and began to analyze the statistical relationship between a datum horizon and the target horizon of the Strawn, which is traditionally done in this area, in order to more accurately image the structure at the top of the reservoir.

Mr. Nelson and I agreed, based on the consistent seismic signature and the consistent log signature, to use the Tubb formation as the datum horizon. We constructed isopachs in the area between the Tubb and the Strawn. We then created an isochron from the seismic data.

We compared statistically the relationships between the time picks and the depth picks. We used that information to construct a velocity gradient.

Based on that velocity gradient through the area, we prepared the depth conversion of the seismic time structure map to the current seismic depth structure map that we've entered in this hearing.

Q. Okay. And you've prepared what's marked Exhibit 9; I think you have a copy in front of you?

A. Yes.

Q. And I think there's been reference to a computer program used. How -- What was done?

A. Okay, we used -- Once we had determined the hydrocarbon pore feet in our interpretation of the pool, we used a computer gridding algorithm to get an unbiased map -- create an unbiased map of the structure. We then modified the contours of that gridded map to reflect our interpretation of the entire pool.

Q. And these results are projected on what's been submitted as Gillespie-Crow Exhibit Number 9?

A. That is correct. The final interpretation of that provided the hydrocarbon pore volume map that we are submitting as Exhibit 9.

Q. In your opinion, does Exhibit 9 accurately reflect original oil in place under each tract within the unit?

A. Yes, it does.

Q. Now, let's get Exhibit 9 in front of you there, Mr. Scolman. And I think you also have Snyder Ranches Exhibit 1, and if you'll turn to, I think, the third page of that, there's the prior -- maybe we can just say the original hydrocarbon pore volume map --

A. Yes.

Q. -- which was given to Snyder Ranches back in December.

A. Yes.

Q. Okay. Before you go into that -- I think it's already been discussed a couple of times -- between the original map and what's being submitted today there was some new data acquired from additional wells?

A. That's correct.

Q. Including an oil-water contact?

A. That's correct.

Q. Could you describe how data like the oil-water contact and the additional data from the wells was used to extrapolate beyond the areas of well control and to come up with the final map that you submitted?

A. Sure. The data represent calibration points. As we get new data, we update our calibration, we update our interpretation of the map.

The well data forms the basis for the time-to-depth relationship, the velocity relationship. It also gives us an indication of the relationship between seismic signatures and of the reservoir parameters, so that as we drill new information our model updates across the entire field.

So one well drilled in one area will potentially modify interpretation across the entire area, as this relationship is modified.

Q. Okay. Now, I don't know if it's on the hydrocarbon pore feet map, but maybe on Exhibit 3 or 4, which you might also have in front of you about the oil-water contact --

A. Uh-huh.

Q. -- the final oil-water contact line that's made, how does that come into play? How can you determine that or use seismic to assist in determining that?

A. Well, once we've converted the seismic time maps to depth, using the relationship here, we can then just -- because we have determined the oil-water contact, we can then have that fit -- that will then fit in the final depth map that's been constructed.

As was stated earlier, it is a constant horizon. So once we've created the contouring map, we know which contour will represent the oil-water contact.

Q. And also, there are certain areas of the pool that don't have -- or, I should say, of the unit -- that don't have much hydrocarbon pore feet attributed to them, like in the southeast part of the pool. How is that determined?

A. We had talked about what the seismic indicates, as far as the geometry of the reef. We see the reef itself as an indication of thickening on the seismic data, and we have noticed an empirical relationship between various seismic parameters, such as amplitude, to indicate the relative reservoir quality.

With the new data from the new wells, we were able to update that model and then update our interpretation of the actual geometry of the reservoir, of the pool.

Q. Also, toward the southeast part of the unit, you have the Hamilton -- I think it's the Hamilton Fed Number 2 well?

A. Yes, sir.

Q. Based upon stepping out from some pretty good wells, that appeared to be a fairly low -- fairly small amount of pay in that well?

A. Yes, sir.

Q. And did that affect the interpretation as far as the southeast part of the unit goes?

A. Most definitely. As far as the southeast corner is concerned, there is a relationship that we derived looking at the various seismic parameters to those calibration points. And based on that, we show that the reservoir quality of the rock deteriorates into the southeast quarter, and the well control is -- seems to back that up.

Q. Do you have anything else you'd like to say on any of these exhibits?

A. No, that accurately reflects the work that we've put into calculating these maps.

Q. Okay. In your opinion, will the granting of these Applications be in the interest of conservation, the prevention of waste and the protection of correlative rights?

A. Yes.

MR. BRUCE: Mr. Examiner, I would pass the witness.

EXAMINER CATANACH: Mr. Kellahin?

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Scolman, do you have a copy of your work on the hydrocarbon pore volume map from November -- it says November 10th, 1994? You see it in Snyder Exhibit Number 1. It should be the second to the last display. Do you have it?

A. Yes, sir.

Q. When you look at the 2-D seismic data -- I think Mr. Crow said there was some earlier 2-D seismic data?

A. That's correct.

Q. Did you use any of that?

A. Yes, sir.

Q. What's the vintage of that information?

A. It ranges in vintage. It's mostly acquired during the 1980s. It's all modern-quality high resolution CDP seismic data.

Q. Do you have a line that shows the shot-point line for the 2-D seismic information?

A. Do you mean a map that would show our --

Q. Yes, sir.

A. -- base map of the information?

Q. Uh-huh, to show where those shot points are?

A. No, sir, I don't have that with me.

Q. You didn't bring it with you, but you have one?

A. We can create a base map in this area --

Q. That would show --

A. That would show --

Q. -- where those shot points are?

A. -- where our 2-D seismic is indicated.

Q. You didn't bring that with you today?

A. No, sir. Since the 3-D coverage contains everything -- you know, goes past where we believe the seismic -- There would be a duplication of the 2-D CDP data and of the 3-D data. 3-D data is more accurate than the 2-D data.

Q. What's the vintage of the 3-D data?

A. We would have acquired that, processed that and began interpretation of that in -- I believe early 1993, it seems like.

Q. All right. Nothing acquired in terms of 3-D data after early 1993?

A. That's correct.

Q. So by the time we get to this map in November 10th of 1994, you had this base set of information on the 3-D seismic work for more than a year? Almost two years? Eighteen months?

A. In that time period.

Q. All right. When you look at the November, 1994, map --

A. Uh-huh.

Q. -- this represents your work product?

A. Yes, sir.

Q. Okay. What is the grid distribution for the 3-D seismic map as we overlay it on this interpretation?

A. The subsurface sample interval, essentially?

Q. Well --

A. How often do we have seismic traces?

Q. That's right.

A. We have traces roughly every 110 feet.

Q. And when we look at that dimension in terms of geometry, is that in the form of squares or rectangles or what?

A. Squares.

Q. Squares, 110 feet per side?

A. Yes, sir.

Q. In order to generate that 3-D seismic work, is there a true shot point, if you will, as we see in 2-D seismic work?

A. Not necessarily, because you are laying out a two-dimensional array of geophones. Any one particular shot point will generate CDP traces over a wide variety of area, so...

Q. Did you bring any of your seismic maps with you?

A. No, sir. Of the time structures or any of the time representations?

Q. Yes, sir.

A. No, sir.

Q. Any of those -- I think you call them isochrons?

A. Right, that would be -- I did not. All of that information has been incorporated in our final interpretation of the hydrocarbon pore volume map.

Q. So to support your ultimate conclusion here today, you didn't bring a velocity map or any of the other subcomponents that got you into this display?

A. No, sir, we did not.

Q. When you take Mr. Nelson's work and move into the area of geophysics, isn't there some calibration that goes on in here?

A. Yes. I mean, that's the whole point, is that you'll use that well data, you'll look at how the well information ties your seismic signatures -- that includes both structuring, amplitudes to reservoir parameters -- and use that information, then, to extrapolate into areas where you don't currently have well control.

Q. And as you make that integration or calibration of your 3-D seismic work into the regular geologic information, there's what they characterize to be ties and mis-ties?

A. Yes. You take -- To do it properly, you would look at the statistical variance between various seismic parameters and various geological or petrophysical parameters.

Q. Do you take that information and generate a report or a map that shows that kind of information?

A. It depends on the goal, and it depends on the match. I do that very diligently when I do my velocity-gradient mapping, to take a look for wells that are in an area that may be a particularly strong velocity anomaly.

Q. Describe for us how -- You go through a system of calibration, I guess, is how I would characterize it.

A. Yes, sir.

Q. Describe for us how you do that and what you did.

A. The process begins with the creation of a synthetic seismogram, which is using the sonic log, which measures the travel time of a formation in the wellbore, and relates that to the speed of sound in rocks. From that, you can make a model of what you believe a seismic trace would look like running through rock at that velocity.

Q. Did you make a seismic trace in this case?

A. Yes.

Q. How many traces did you make?

A. Well, you make one. It becomes a pseudoseismic trace at the wellbore.

Q. A seismic trace -- Help me understand the 3-D work. Is that a display of the entire reservoir when I see a seismic trace?

A. No, sir, that would represent a close approximation of the echoes from the various formation boundaries as the sound wave was propagated vertically through the earth.

At various formation interfaces, due to the changes in velocity and density, an echo -- some energy will be reflected back, additional energy will propagate back through.

Q. So in 3-D work I'm going to see a similar seismic trace that I would see from a geophysicist with the 2-D presentation?

A. That's correct.

Q. The seismic traces would look similar?

A. That's correct.

Q. All right. You say you take that and you're going to integrate it back into a -- What was it? A sonic log?

A. Well, you start with a sonic log, create a pseudoseismic trace --

Q. All right.

A. -- basically a model seismic trace, from the sonic information.

Q. The sonic logs. Do you take each and every sonic log in the pool and do that?

A. In most cases, yes. It depends on --

Q. Do you do that here?

A. In most cases. I don't believe I made a synthetic in every case.

Q. All right. What happens next, then?

A. Once that calibration is done, you compare your model seismic trace, the synthetic seismogram, to the trace from the seismic, and you try to get -- the first thing to establish is which reflectors in the seismic represent which geologic layer boundaries.

Q. All right. You can generate that in terms of a printout, can't you?

A. No, you really can't. Because of the inherent differences in a sonic log measuring of the speed of sound in the rock and the seismic measuring the speed of sound in the rock, it is better to use an interpretation, to go ahead and use, say, your breadth of knowledge in making that calibration through an entire trend, to go ahead and fit those reflectors, to take a look at which reflectors on the synthetic trace you believe match which reflectors on the actual seismic data.

Q. All right. When you go through this calibration to generate information, at what point do you generate the first hard copy of information? Is that the velocity map?

A. As far as a map view goes?

Q. Yes.

A. No, generally the first map that we'll create would be a structure in time on important formation tops.

Q. Okay. In terms of structure, then, what happens? Do you further refine that as part of your investigation?

A. Yes. sir. It depends on the nature of the reflectors that you're mapping on. In this part of the world, the Strawn is a good-quality seismic reflector. It's a fairly simple acoustic interface between the overlying shales and the carbonate.

So the time structure is interpreted, the reflector is interpreted, and we take a look at that time surface to get an initial idea of the structuring of the reservoir.

Q. All right. What happens next?

A. Using the wellbore information, we take a look at the statistical relationships between the actual depth from the logs to the -- that time surface -- to the surface, depth surface, of the Strawn, versus the structure of the seismic time.

The most important thing that we look for is relationships -- is the relationship between the depth surface, from the log information, and the time surface from the seismic information.

And if there's a fairly simple velocity gradient, if the rock is relatively uniform over the reservoir, your time surface will very closely mirror your depth surface. Your highs will be high, your lows will be low, your dip rates will be roughly the same.

Q. When you're working with Exhibit 9, which is the final work product of this effort, to get the hydrocarbon pore volume map --

A. Yes, sir.

Q. -- did you use Mr. Crow's isopach or structure map that are Exhibits 3 and 4?

A. Let's see, Exhibit 3 and 4.

Q. Do you want to look at them?

A. Please. Oh, they're in my pile.

Yes, sir, the depth map that is presented here is effectively -- We were in agreement when I made my depth map from the seismic, Mr. Crow and I were in agreement, as was Phillips, into the shape of the depth surface in this pool.

Q. All right.

A. The net ϕ, the porosity map, is used in a different -- Those are used in calibrations of the reservoir quality; they're not used in the depth creation.

Q. When you look at the structural component of the reservoir --

A. Uh-huh.

Q. -- the seismic data you had is generated early 1995. And so as we move in -- I thought you said early -- I'm sorry, early 1993 --

A. Thank you.

Q. -- I misspoke. Early 1993.

So as you move into November of 1994, the only thing that's happening is, you get additional log information?

A. We drilled some additional wells.

Q. And so by November of 1994, we have what's shown before you as Snyder Exhibit 1, with the series of isopach, structure map and a hydrocarbon pore volume map, and that's where we were talking a while ago?

A. Right. And as I said, we changed -- When we first did our work that led up to the maps of late 1994, we were using rough relationships for the area between the time and the depth picks, between seismic and well information. We used that, then, to qualitatively shape our contours to extrapolate a well away from the well information.

Then subsequently, once we had drilled the new wells and we realized that we wanted to do this to our very, very best efforts and that we had additional calibration points, I then expanded our efforts to do a new -- to take in more area so that I could start to establish these relationships empirically as we were talking about these statistical relationships between the time and the depth data in a larger area than this field proper.

Statistically, you will want to look at a large area to make sure that you're seeing the true trends.

Q. When we look at -- There's various of these maps that have Gillespie's conclusion about the oil-water contact --

A. Yes.

Q. -- the minus 7617 number?

A. Yes.

Q. That is generated out of log data, is it not?

A. That is correct.

Q. You're not going to be able to generate an oil-water contact by looking at seismic information?

A. In this particular reservoir, no, I do not believe I see an oil-water contact.

Q. Did you work with any reservoir engineer to determine by material balance whether or not the gas or hydrocarbons that he would calculate to be in place on a material balance analysis would fit into the size of container that you've mapped here as Exhibit 9?

A. I knew of the numbers that they were calculating for material balance, but we used that as essentially a set of checks against the interpretation.

I did not want to bias an interpretation. I wanted to let both the seismic data and the well data give me my best -- Mr. Nelson and I -- the best interpretation we could of the geologic information to explain the reservoir, and then once we had that, look for -- compare that back to the material balance and see if we believed we had roughly the same pool described.

Q. Do you generate a map prior to helping produce the hydrocarbon pore volume map? Do you generate a seismic display of some kind --

A. Yes, sir.

Q. -- that is before this?

A. We'll go from a seismic time map, create --

Q. Okay. What's the next in sequence?

A. -- create a velocity-gradient map.

Q. Okay.

A. Multiply the two together, velocity times time, will give you a depth map.

Q. Okay.

A. There are various seismic displays or effectively maps of reservoir attributes, those --

Q. What kind of things would you have displays of? What attributes are you describing?

A. That would include maps of reservoir top to reservoir bottom. That would include various isochrons between overlying and underlying formations. It would include amplitude, frequency and phase displays, the top of the reservoir, the base of the reservoir.

All of that information is -- I use all of that at the local area, my experience in the trend through this entire area from studying other fields and 2-D and 3-D seismic responses in those other fields, to come up with my final interpretation of the data.

Q. Do any of those displays include what I would characterize as an isopach?

A. Yes, sir. For the analysis done for this display, when I went ahead and started to establish these statistical relationships, those are done between a datum horizon and the target horizon.

So there would have been a Tubb-to-Strawn isochron created, a velocity-gradient map between the Tubb and the Strawn, and then the final -- the multiplication of those two together would give you a depth isopach between the Tubb and the Strawn.

Q. Now, tell me again why you used the Tubb.

A. When you go after a datum in this part of the world, you're looking for several characteristics. You would like a formation top that is present in the majority of wells in the area. Because of the Wolfcamp penetrations in this part of the world, there are several -- there are far more Tubb penetrations than there are Strawn penetrations.

You're looking for a bed horizon that has extremely good predictability and is easy to pick on both the wireline log information and on the seismic information, so --

Q. Do you, in effect, generate a Tubb map?

A. Yes, sir.

Q. What was the depth of the Tubb? Do we have a marker point somewhere that you can show us where you picked the Tubb?

A. Shows what the Tubb is?

Q. Yeah.

A. I don't believe the cross-sections will go shallow enough to show that.

Q. I don't think so either.

A. The Tubb is a basinwide pick out here. It's a shale marker, and it is widely recognized as a pick in this formation.

Q. Did you bring anything by which we could verify or validate your pick of the Tubb?

A. No, sir.

Q. Did you bring any of these maps or displays that were generated or could be generated as part of the analysis?

A. No, sir, all of that analysis has been incorporated in our final representation of the HPV map.

MR. KELLAHIN: Mr. Examiner, I've got a serious problem here.

It is impossible to ask further questions of this witness without having him ready to produce and discuss the maps and their intermediate components that have gone into this final resulting display. It makes it impossible for me to effectively cross-examine him as to his work product when he fails to bring his report and all the supporting data.

There are several options.

We can try to complete the case today with leaving the record open on that issue.

Another option is to simply strike his testimony and to exclude the conclusions with regards to the seismic information because I've been denied the opportunity to examine him on the details of his report.

I quite frankly don't know where this is going to take us, Mr. Examiner, but it's impossible for me to go forward with this witness, based upon the fact that I cannot examine him on the details of his work, because he didn't bring it with him.

EXAMINER CATANACH: Mr. Bruce, do you want to respond to that?

MR. BRUCE: Mr. Examiner, first of all, they've got their own experts. They were given access to every bit of data that Dalen and Gillespie had. They can present their own countervailing testimony.

Number one, there was no subpoena. We did this voluntarily. We weren't required to bring all the data. He's testifying on these exhibits based upon his own personal knowledge, and that's all that is required. He does not have to bring up every single map and show it to the opposing side. That's never been the requirement in this Division or, for that matter, before the District Courts in this State.

We have had substantial testimony about what went into the formation of this map, what was done, what was used. That's all that's required. The evidence is perfectly valid. It cannot be struck, and we should just go on. If they have another interpretation, let them put it on.

EXAMINER CATANACH: Mr. Kellahin, is that a correct understanding, that this information was available to your parties?

MR. KELLAHIN: My expert was provided the opportunity to go to Dalen's office to view the seismic information. We were not afforded or allowed to duplicate or have copies of the data tape or any of the hard data involved in the study.

The review of information was tightly controlled by Dalen, and there was simply no reasonable opportunity afforded to us to have access to the information.

There were no maps of any kind, from start to finish, provided for us to discuss, analyze, review or determine if they were valid or if we had different conclusions about that.

My preference would be to finish the witnesses as far as we can finish them today and then to continue this case and have the Division issue a subpoena, and I will get the hard data to have my expert have a full opportunity to rebut this witness.

MR. BRUCE: Mr. Examiner, they voluntarily agreed to this procedure. This is proprietary, confidential data. They agreed to the procedure that they would go to Dalen's office and look at it there.

Phillips did the same thing, exact same thing. They were given the exact same access to data that Snyder Ranches was given.

This is just wrong, if this hearing is continued and this charade is continued. In the past, the only thing the Division has ever required under a subpoena is raw data. Raw data, period. That's what they had.

Mr. Scolman has testified what he's done, and that's all that's necessary. Mr. Kellahin, Snyder Ranches is not entitled to another bit of data.

EXAMINER CATANACH: Is it my understanding that they do have the raw data, Mr. Bruce?

MR. BRUCE: They were provided -- Dalen -- They went to Dalen's office, and under a confidentiality agreement signed by Snyder Ranches' witnesses, that's what we agreed to do.

Phillips did the same thing. They went to Dallas, looked at the data there.

MR. KELLAHIN: That's a mischaracterization of my understanding of this situation.

We were not given the raw data. We signed a confidentiality agreement, we would hold confidential and proprietary their data without disclosure. But the only access they gave us to the data was on a computer screen, and they refused to give us the data.

MR. BRUCE: That's the same thing we did with Phillips.

MR. KELLAHIN: Phillips is not an opponent, Mr. Examiner.

And so that's my problem, is, we had a view of it on a computer screen and no opportunity to analyze and study the data.

And we'll certainly hold it confidential. There's ways to handle confidentiality problems, and we're willing to abide by that.

But it's inappropriate for us not to at least have the raw data.

MR. BRUCE: Well, they're asking for beyond that. They're asking for all of Mr. Scolman's work product; they're not asking for the raw data. Apparently they don't give a damn about the raw data. They want everything Mr. Scolman did from 1993 forward, and that's a totally separate matter.

EXAMINER CATANACH: Mr. Kellahin, I believe that prior to this hearing you did have the opportunity to subpoena that data yourself, and you did not take that opportunity and use it.

I think that what we have here is, we have the finished product of this interpretation that you can base your cross-examination on. I think that it's not necessary for us to continue this proceeding at this point.

I think I'm going to rule just to go ahead and proceed with this.

MR. KELLAHIN: Thank you, Mr. Examiner. That concludes my examination then.

EXAMINER CATANACH: Do you have anything further, Mr. Bruce?

MR. BRUCE: I have nothing further of this witness.

EXAMINER CATANACH: This witness may be excused.

MR. BRUCE: I have one last witness, Mr. Examiner, just to put in some land testimony. It shouldn't take very long.

PAUL S. CONNER,

the witness herein, after having been first duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Would you please state your name for the record?

A. Paul S. Conner.

Q. And who do you work for?

A. I am president of Unisource, Incorporated, Denver, Colorado.

Q. What type of work does Unisource perform?

A. We specialize in all types of agreements, federal exploratory agreements, cooperative agreements.

Q. Okay. And you act in the capacity of a landman?

A. Yes, sir.

Q. Are you a certified professional landman?

A. Yes, sir, I am.

Q. And what is your relationship to Gillespie-Crow, Inc., in this case?

A. I'm an independent contractor that was hired in the preparation of unit documents and to facilitate the ratification and joinder of parties to the agreements.

Q. Have you previously testified before the OCD?

A. Yes, sir, I have.

Q. As a landman?

A. Yes, sir, I have.

Q. And were your credentials as a petroleum landman accepted as a matter of record?

A. Yes, they were.

Q. And are you familiar with the land matters pertaining to this unit insofar as it pertains to the -- attempting to acquire the joinder of the royalty interest owners in the various tracts in the unit?

A. Yes, sir.

MR. BRUCE: Mr. Examiner, I tender Mr. Conner as an expert petroleum landman.

EXAMINER CATANACH: Mr. Conner is so qualified.

Q. (By Mr. Bruce) Mr. Conner, what is Exhibit 19?

A. Exhibit 19 is the unit agreement to the West Lovington-Strawn unit area, and it's a standard form that was previously accepted by the BLM, the Land Commissioner and the OCD.

The operator designated under this agreement is Gillespie-Crow, Incorporated.

Q. Now, attached as part of this agreement are copies, I think, and originals were submitted to the Division with its copy, but does this contain copies of the ratifications of the various parties which have been received to date?

A. Yes, sir, it does.

Q. Both working interest and royalty interest?

A. Yes, sir, that's correct.

Q. As you said, this is a standard form. In your opinion, is this unit agreement form fair and equitable?

A. Yes, sir.

Q. How many working interest owners and royalty owners are there in the unit?

A. There are eight working interest owners, 67 royalty owners and eight overriding royalty owners.

Q. Do you seek to statutorily unitize any working interest owners?

A. No, sir, we don't. We own obtained 100 percent of the working interest owners' commitment to the unit -- to the unit and operating agreement.

Q. What percentage of royalty owners have ratified the unit?

A. Unisource has obtained ratification and joinders from royalty owners that represent 83.065 percent.

Q. Now, referring to Exhibit 20, what does that reflect?

A. Exhibit 20 is a spreadsheet that Unisource prepared that shows the calculation of the interest of the royalty owners in the unit.

Q. Okay, and this lists all the royalty override, anybody of that type, it lists all of those persons?

A. That's correct, overriding royalty and basic royalty owners.

Q. Okay. Now, who do you seek to statutorily unitize?

A. There are a number of parties that we seek to statutorily unitize, and they would be shown on Exhibit 21-A.

Q. Okay, 21-A lists parties with whom you have not had any contact at this point -- or I mean, I should say any, return of the ratification --

A. That's right, 21A represents the parties who, to our knowledge, have received the agreements but have not ratified the agreement.

Q. Okay, and what does Exhibit 21-B represent?

A. Exhibit 21-B is a spreadsheet. It's the same spreadsheet as Exhibit 20, except that it has deleted those parties who have ratified the unit agreement. So this is a representative of the parties who have not committed to the unit at this point.

Q. Okay. Now, were there some non-locatable royalty owners?

A. Yes, sir, there were.

Q. And were they notified by publication?

A. Yes, sir, they were.

Q. Is Exhibit 22 an affidavit of publication regarding this unitization case?

A. Yes, sir, it is.

Q. And you do seek to unitize the unlocatable parties also; is that right?

A. Yes, sir.

MR. BRUCE: One thing, Mr. Examiner: This publication was done when the Applicant was Charles B. Gillespie, Jr., individually. This was run after the Application was initially filed.

We have subsequently republished notice, but I have not yet received the affidavit of publication from the paper down in Lea County, and I ask permission to submit that as soon as I get it. It should be in a week or so.

EXAMINER CATANACH: Okay.

Q. (By Mr. Bruce) Have the Bureau of Land Management and the Land Commissioner preliminarily approved the unit?

A. Yes, sir, they have.

Q. And does Exhibit 23 contain their -- I guess what they do is preliminarily approve it; is that correct?

A. That's correct.

Q. And Exhibit 23 contains their letters of preliminary approval?

A. Yes, sir.

Q. Have Mr. Gillespie and Gillespie-Crow, Inc., in your opinion, made a good-faith effort to secure a voluntary unitization of the royalty owners?

A. Yes, sir, they have.

Q. And has written notice of this unitization hearing been given to all locatable parties who did not voluntarily join in the unit?

A. Yes, sir, notice was given.

Q. And is Exhibit 24 your affidavit of notice containing the various notice letters?

A. Yes, sir, it is.

Q. We'll get into this a little bit in a minute.

Originally, you did notify all of the royalty owners, back in December, of the originally proposed January, 1995, hearing?

A. That's correct.

Q. And then what you did was, on May 10th you renotified the persons of the hearing date?

A. That's correct.

Q. And then by letter dated May 25th you also notified them of the change of the operator; is that correct?

A. That's correct.

Q. And this is all contained in Exhibit 24?

A. Yes, sir, it is.

Q. Now, regarding the commitment of the royalty owners to the unit, would you refer to your Exhibit 25 and discuss contacts with the royalty owners over the past several months?

A. I'm sorry, could you state the question again, please?

Q. Yeah, do you find Exhibit 25 --

A. Yes, sir, I've got it.

Q. -- in the package?

A. Yes, sir.

Q. Could you describe your written and verbal contacts with the royalty owners and what response you've got from them?

A. Okay, typically we have a very standard letter that we mail out to the royalty owners that explains the procedure, it explains that enclosed with our letter are the unit agreement and Exhibits A and B and C to the agreement, along with ratification and joinders, and that they are given the invitation to commit their interest to the unit area.

We did not contact verbally every one of the royalty owners. We did have some contact with royalty owners who did call and asked questions about the procedure and so forth, and we feel that we adequately answered those questions.

Q. Okay. Your initial mailing was December 5, 1994?

A. Yes, sir, it was.

Q. And there were some handwritten corrections in there --

A. Yes, sir, it's --

Q. -- some typographical errors?

A. Well, it wasn't -- It was a misunderstanding on my part that it was going to be gas injection and not waterflood.

Q. Okay. And that was corrected by your December 27 letter?

A. Yes, sir, it was.

Q. And your December 29, 1994, letter was your original notice to the owners regarding the original hearing date?

A. That's correct.

Q. What was the May 10th, 1995, letter for?

A. May 10th, that letter again was another mailing out to the working -- or to the royalty and overriding royalty owners, explaining that there have been two additional wells drilled in the unit, that there have been some minor changes to Exhibits A and B, and that because of the results of the two wells that were drilled, Exhibit C changed as well, and the parties were notified of that, and also we were advised that the parties should re-execute the agreements because of the changes, so we mailed out additional ratification and joinders and requested that new ones be signed and returned.

Q. Okay. And as I think you mentioned, during this several-month period you did have a number of telephone conversations with royalty owners that called you up --

A. Yes, sir, we did.

Q. -- and inquired about the project?

A. Yes, sir, we did. I would say that we had an inordinate -- not an inordinate but a very minor amount of calls in relationship to other waterfloods or injections that we have done, so it appeared to me that many of the royalty owners were in agreement with this and understood what was happening.

Q. Were Exhibits 19 through 25 prepared by you or under your direction?

A. Yes, sir, they were.

Q. And in your opinion, will the granting of the unitization Application be in the interests of conservation, the prevention of waste and the protection of correlative rights?

A. Yes, sir, it is.

MR. BRUCE: Mr. Examiner, we move the admission of Exhibits 19 through 25.

EXAMINER CATANACH: Exhibits 19 through 25 will be admitted as evidence.

MR. KELLAHIN: May I have just a moment? Just a moment, Mr. Examiner.

(Off the record)

MR. KELLAHIN: Mr. Examiner, by stipulation with opposing counsel, I move the introduction of what we've marked as Snyder Ranches Exhibit 4. It is Mr. Conner's letter of December 5th, 1994, to the royalty and overriding interest owners.

A matter of significance to me is that I've attached to it the map, which is still the same map of tracts, right after the letter, and then the next thing is

Exhibit C, which is the distribution of participation per tract based upon the hydrocarbon pore volume distribution in November.

And then after that is the formula, and then followed by Exhibit B that Mr. Conner sent out showing the interest ownership.

And with that stipulation, then, we would move the introduction of Exhibit 4, and I would have no questions of Mr. Conner.

EXAMINER CATANACH: Exhibit 4 will be admitted as evidence.

Just a couple of questions for Mr. Conner.

EXAMINATION

BY EXAMINER CATANACH:

Q. What percentage of the royalty interest owners were not located, Mr. Conner?

A. It was a small percentage. One interest of note would probably be Earnestine Gillespie; she represented 5.39 percent. And the other parties had very minor interests.

EXAMINER CATANACH: That's all I have. The witness may be excused.

MR. BRUCE: That's all I have on our direct case, Mr. Examiner. I'm not sure what you prefer. As you know, Phillips may have somebody to present. I don't know if they want to present it now or -- and then of course Mr. Kellahin.

EXAMINER CATANACH: I guess we ought to take a lunch break at this point and then just -- Does Phillips have a witness they plan on putting on?

MR. CREMER: At this point it appears that we probably will. We will probably prefer to present them in rebuttal, though, to the testimony that's already been --

EXAMINER CATANACH: Okay --

MR. KELLAHIN: I'm confused. Does he have a direct witness, or is he simply going to wait to see what my witnesses say?

MR. CREMER: That's -- Yeah.

MR. KELLAHIN: Is that what you want to do?

MR. CREMER: Yeah.

MR. KELLAHIN: Just wait for -- hold them for rebuttal?

MR. CREMER: Right.

MR. KELLAHIN: Okay.

EXAMINER CATANACH: Okay, so we'll start with your case right after lunch.

(Thereupon, a recess was taken at 11:45 a.m.)

(The following proceedings had at 1:07 p.m.)

EXAMINER CATANACH: Okay, I think we're ready. Let me call the hearing back to order, and I'll turn it over to Mr. Kellahin.

MR. KELLAHIN: Mr. Examiner, a housekeeping chore.

I believe I neglected to have you admit Snyder Exhibits 2 and 3. They were the structure map and the isopach map that Mr. Crow submitted at the January 19th hearing. And if I have not already done so, we would move the introduction of those two displays at this point.

EXAMINER CATANACH: Okay, Snyder Exhibits Number 2 and 3 will be admitted as evidence.

MR. KELLAHIN: At this time I'd like to call our geologic witness, Michael Clemenson. He resides in San Antonio, Texas.

MICHAEL G. CLEMENSON,

the witness herein, after having been first duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. KELLAHIN:

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

A. Michael G. Clemenson. I'm a petroleum geologist.

Q. You'll have to -- The hum of the heater or the air conditioner or whatever they're running at the moment, you'll --

A. I hope it's the air conditioner.

Q. Well, we're going to find out. You'll have to speak up over that hum.

A. All right.

Q. Summarize for us your education, if you will, sir.

A. I'm a 1978 -- or 1979 -- *summa cum laude* graduate of Texas A&I University at Kingsville, Texas. I have a bachelor's degree in geology. I also have a master's degree in environmental science.

Q. Are you a member of any professional group of petroleum geologists?

A. Yes, the AAPG.

Q. Summarize for us your professional employment as a geologist.

A. In Kingsville, Texas, I worked for Exxon Company, USA, as a development geologist.

Subsequent to Exxon, I've worked for Tenneco Oil Company for a number of years, where I worked the Permian Basin in west Texas.

Q. As part of that work, would you summarize for us the kinds of reservoirs that you have had extensive geologic experience in, either exploration and/or development geology?

A. Well, since 1984 I've been a consulting petroleum geologist, and through my career with Tenneco and both as a consulting petroleum geologist, I've worked with a number of reservoirs in the Permian Basin area, both in Texas and New Mexico, Delaware sands, San Andres carbonates, Strawn carbonates, Wolfcamp carbonates, the Ouachita overthrust trend.

Q. When we talk about this Strawn algal mound in Lea County, New Mexico, is that the type of Strawn reservoir that you have had past experience in as a geologist?

A. Yes.

Q. As part of your consulting services to various clients, have you been retained by Snyder Ranches, Inc., to make a geologic investigation of the West Lovington-Strawn Pool?

A. Yes, I have.

Q. As part of that work, did you work in consultation with Mr. Terry Payne, the reservoir engineer with Ronnie Platt's firm out of Austin, Texas?

A. Yes, sir, I did.

Q. As part of that work, did you have available to you all of the geologic and log information from all the wells within the pool?

A. I had well-log information provided to me. I had mud-log information.

Q. Did you visit with or consult with personnel or representatives of Gillespie in analyzing that type of data and information?

A. I don't remember the specific date, but Terry and I took a trip up to Dallas to visit Mr. Scolman and Mr. Nelson, and there we reviewed some data.

Q. Okay. Did you satisfy yourself as a geologist that you had sufficient geologic information by which to prepare a structure map, an isopach, and help prepare a hydrocarbon pore volume map on the West Lovington-Strawn Pool?

A. I had available to me basic geologic tools, being well logs, which were subsequently interpreted by Platt, Sparks & Associates, mud-log data, and primarily that was it. I mean, I got to look through their files.

There was -- I had an opportunity to look at some seismic data on a computer screen. I asked some questions about that specifically, where is the location of the array of geophones, and I -- and how was the velocity-to-depth calculations made? And those were questions that were not answered.

Q. Were you provided an opportunity to take a copy of the database or the data tape that went into the 3-D seismic work?

A. No.

Q. When we look at the log information, were you satisfied that you had sufficient log data to accurately

construct a structure map and an isopach of the reservoir?
A. Yes.
Q. And have you done that?
A. Yes, I have.
Q. And based upon that work do you now have certain geologic conclusions and opinions about that reservoir?
A. Yes, sir, I do.
MR. KELLAHIN: We tender Mr. Clemenson as an expert petroleum geologist.
EXAMINER CATANACH: He is so qualified.
Q. (By Mr. Kellahin) Let's turn to the structure map, Mr. Clemenson. It's marked as Snyder Exhibit Number 5. This represents your work product, does it, sir?
A. Yes, sir.
Q. You have indicated on your display an oil-water contact at minus 7617; is that not true?
A. Yes, sir, it is.
Q. Describe for us how you reached that conclusion as to the oil-water contact in the well.
A. Very simply, that number was provided to me by Terry Payne at Platt, Sparks & Associates, based on his log analysis, and I think this also agrees with the data that's been previously presented here today.
Q. Do you have any knowledge or information to show evidence that would indicate a contrary conclusion about

the oil-water contact?

A. No, I don't.

Q. Describe for us how that oil-water contact, then, is of significance when we look at your structure map.

A. The significant thing about the oil-water contact is, as it does in many reservoirs, almost every reservoir, is that it follows structural contours.

Q. And that is the way you have mapped it here?

A. Yes, sir, I have. I have mapped it at minus 7617, and you see it here on this map just below the minus-7600-foot contour.

Q. Apart from the few acres in the north half of the northwest-northwest of 34, where the oil-water contact moves into the unit, despite -- Apart from that, all the rest or balance of the unit is free of water, it's above the oil-water contact?

A. Yes, sir, it is.

Q. Do you see any evidence of information that would reach a contrary conclusion?

A. No, sir, I do not.

Q. When we look at the structure, do you find geologic evidence by which you could interpret a nose, a structural nose, moving from north to south in the northwest quarter of Section 34?

A. No, sir, and actually to the contrary, I have used some additional well data outside the boundaries of the unit to establish a firm trend through this area, and nowhere on this map do you see the top of the Strawn reef below minus 7600 feet on any well top.

Q. I'm sorry, say that again.

A. You don't find the top of the Strawn mound at below minus 7600 feet on any top here. The 7600-foot contour is based on a minus 7592 in the Atlantic Chambers and minus 7583 in the BTA Townsend, both of which are a few hundred feet north of the northern boundary of the unit.

Q. In order to draw a nose moving into the northwest quarter of 34, what would have to happen then?

A. You would have to drill a well there and find it below minus 7600 feet.

Q. Is that likely to occur?

A. I wouldn't think so.

Q. Let's look at the structure map presented by Mr. Crow. It was his Exhibit Number 4 today. I'll give you a copy of that.

Starting at the bottom of the displays, to the south of each display, there appears to be some general similarity in the southern portion of the unit, does there not?

A. Yes, sir.

Q. How did you go about verifying or determining the accuracy of your contouring of the structure on the southern half of the unit area?

A. Well, very simply, I looked at the log data, found the tops of the formations and contoured that data.

Q. When you look at Mr. Crow's structure map, his information on the structure map stops in close proximity to the boundaries of the unit, does it not?

A. I'm sorry, repeat that.

Q. Yes, sir. When you look at Mr. Crow's structure map --

A. Okay.

Q. -- his contour lines stop or terminate in close proximity to the outer boundaries of the unit?

A. Yes, sir, they do.

Q. You can't read this and tell how it fits regionally into the structure?

A. There's -- Yeah, there's no other wells in the trend to establish where these contours might extend to off the unit boundary.

Q. Give us that additional information, then. As we move east and west of the unit, structurally, what do you see here as we pick up additional well control?

A. As you move to the east and slightly north of the Bridge Number 2 Culp, you find the -- in the southwest of the southwest of Section 26, you the Atlantic Number 1

Chambers, which has penetrated the top of the Strawn mound at a subsea top of minus 7592. That establishes an accurate point from which to begin a minus 7600-foot contour.

Q. On the other side of the unit, what do you use for a control point?

A. On the other side of the unit, there are two additional control points that I used, one being the Mitchell Number 1 Bear, penetrated the top of the Strawn mound at minus 7534 in Section 32, and additionally, the BTA Townsend Number 1, which penetrated the top of the Strawn mound at minus 7583.

Q. When we look and compare the two structure maps, where is the point of greatest disagreement between you and Mr. Crow?

A. Well, obviously that would be in the northwest quarter of Section 34.

Q. Okay. When you prepared your structure map, did you have available to you, either through Mr. Payne, me or anyone else, the tract configurations within the unit or an identity as to the ownership of any tract within the unit?

A. No, one thing that I do in cases like this, when I start a map like this, I start with simply the township and range and spot the wells based on the C-105 reports from the State and then contour my data independent of what any tract configuration might be inside, or even, for that matter, the unit boundary.

Q. And did you apply that same method to the isopach and to the hydrocarbon pore volume map?

A. Yes, sir, I did.

Q. All right. Let's turn to the isopach. It's Snyder Exhibit Number 6.

A. This would be the net pay, or hydrocarbon pore feet, which would you prefer?

Q. Exhibit 6, I have, is the net pay map of porosity greater than --

A. I re-numbered mine.

Q. Okay.

A. All right.

Q. Describe for us how you've constructed your map.

A. This is a map that is based on net pay with porosity greater than three percent. The numbers that you see next to the wellbores are the net-pay numbers that were provided to me by log analysis done from the computer program by Platt-Sparks. In other words, they generated the numbers, gave them to me, and from those numbers I contoured this map.

Q. The log analysis work, then, was performed by Mr. Payne and Platt-Sparks, and not by you?

A. That is correct.

Q. Okay. Those values, then, are defined in terms of the porosity values per well, and those numbers are those numbers in close proximity to those wells? Is that what I'm looking at?

A. Yes, sir, you are.

Q. How did you make judgments and decisions about how to connect all those control points with the porosity values given into a map like this?

A. Well, obviously, you see a distribution of points from highs ranging at 129 in the Speight well to lows that are in the 30s range.

For example, the Number 2 Hamilton there is 32 and the Number 2 Earnestine is 35, and you interpret the contour intervals between those two points --

Q. When you look at the Speight well --

A. -- or those several points, I should say.

Q. When you look at the Speight well down in the northwest quarter of Section 1, the greatest value of porosity thickness, if you will, is 129 feet?

A. That's correct.

Q. And so what does that tell you in terms of contouring?

A. Well, one basic geologic rule is that you never contour higher than the highest amount of data that you have. If you have 129 feet, you would not make a 130-foot contour --

Q. Let's turn to Mr. Crow's map, which is Exhibit Number 3.

A. Let me finish that. -- because there's no evidence that it is higher than 129, based on the log analysis.

Q. Well, then, your best information in those terms and conditions is what, sir?

A. Log analysis.

Q. Let's look at Exhibit 3, Mr. Crow's map. You were provided a thickness from Mr. Payne of 129 feet for the Speight well. Mr. Crow's isopach has 131 feet, I think?

A. Yes, sir, it does.

Q. What does he do, though, with his contouring in this area in terms of the greatest thickness of log information he reports?

A. His greatest information by log analysis is 131 feet of porosity greater than or equal to three percent. Yet he contours all the way to some value above 160 feet. So he has added 30-some feet of reservoir across that area.

Q. Is that appropriate?

A. In my opinion, no.

Q. If you're adding thickness to the Speight well, greater than the indications on the log analysis, what effect does that have when you get around to preparing the hydrocarbon pore volume map?

A. Obviously, you'll add more hydrocarbon pore volume in that area and give that tract more oil. It has to do with the distribution of -- distribution of the pore volume across the reservoir.

Q. When you look at Mr. Crow's isopach, does he show you a value where he has identified and reached the conclusion about the oil-water contact? Is that on that exhibit?

A. Not on this net porosity greater than or equal to three percent. I just see -- Well, let me look at this. No, I don't see it on here.

Q. All right. Is it on the structure map?

A. No.

Q. All right. It was from his testimony, then, that we've picked up his agreement with you about the oil-water contact?

A. Yeah, on one of these maps it's labeled minus 7617.

Q. All right. Describe for us in the reservoir where that oil contact -- oil-water contact -- is going to be, as we move to different locations in the reservoir. How will we find it again? Is it related to structure or isopach thickness or what?

A. It's directly related to structure.
Q. So what does that mean?
A. It means that as you move to the north, that is to say, downdip, you will encounter the water leg of this reservoir at minus 7617, as shown here on my Exhibit Number 6.
Q. And that is the highest point of known water in the reservoir --
A. Yes, sir.
Q. -- minus 7617?
A. Yes, sir.
Q. No indication or evidence to include -- or to support a conclusion that it would be higher in the reservoir than that?
A. No, sir.
Q. All right. Moving from your isopach, describe for us Exhibit 7, which is the hydrocarbon pore volume, or hydrocarbon pore feet map.
A. This map represents the distribution of the hydrocarbon pore volume within the West Lovington-Strawn reservoir.
Q. Describe for us on Exhibit 7 how you and Mr. Payne prepared this.
A. Mr. Payne calculated the numbers for hydrocarbon pore feet by using thickness times porosity times oil

saturation, the product of those numbers being the number that you see posted next to the wells.

And again, this map was contoured independent of where the unit boundary was and independent of where the tracts were. So I believe that it represents a -- the most fair map possible.

Q. If you had an interest within any of the tracts in the unit or were working for a client that had those interests, regardless of what tract it's in, would you be comfortable in receiving a share or having your client receive a share based upon this distribution?

A. Yes, I would.

Q. And why is that?

A. Because it was drawn independent of any kind of boundary, any kind of lease-unit boundary.

Q. You have part of the reservoir that extends outside the unit, don't you?

A. Yes, sir, I do.

Q. How did you reach that conclusion?

A. The Bridge Number 2 Culp has a portion of the mound facies in it.

Q. You're looking at the well in the east half of the east half of 34?

A. Yes, sir.

Q. And so when you look at the log of that well, what does it show you?

A. Well, it shows that a portion of the mound facies is present in that well, and additionally that that well drill stem tested some hydrocarbon shows, some gas to surface in an hour and 45 minutes. No rate was given; I have it on this -- and 130 feet of gas-cut mud.

Although -- And even though the facies is there, it is tight, it has very little porosity in it, not enough porosity to map hydrocarbon pore volume in that well.

Q. So what does that information tell you as a geologist as to where to put the zero contour line in relation to the unit boundary?

A. Well, I didn't draw my zero line with regard to where the unit boundary was; I drew it based on my best estimate of where I would think that this reservoir would end.

Q. When we look at the Applicant's hydrocarbon pore volume map, Exhibit 9, how did the Applicant handle that data?

A. Well, when you look at this map, it appears as though all of the contours get crowded together at that one space and put up right next to the unit boundary for some reason.

Q. How did you make decisions about the northern side of the boundary in distributing the hydrocarbon pore volume?

A. I laid one map over the top of the other. I found the structural contour that was coincident with minus 7617 and drew that line on this map, being the hydrocarbon pore feet map, and that is where the water table or the wet portion of this reservoir intersects the zero porosity line.

Q. Let's have you take your Exhibit 7, your pore volume map, and compare it to the Applicant's Exhibit 9, the pore volume map that was presented by the Applicant, and show us the points of greatest disagreement.

A. Well, again, the point of greatest disagreement would be in the northwest quarter of Section 34.

Q. And what has occurred on their distribution of the reservoir versus yours?

A. They draw their oil-water contact further south than I do.

Q. When you go back to the prior maps of the Applicant, which is the November, 1994, maps --

A. I don't think I have a copy of those here, sir.

Q. I'm trying to find some. When we go back to the November, 1994, maps, if you'll look at their isopach in November of 1994 and compare it to your isopach map --

A. As far as where the zero contour is?

Q. Yes, sir, particularly along this northern boundary, which is where we have the greatest dispute. Do you see Mr. Crow's isopach?

A. Yes, I do.

Q. Ho does his conclusions about the location of his zero line compare to your conclusions about the location?

A. In general they're, you know, in the same area, they're within a few hundred feet of the northern boundary of the unit.

Q. All right. His was done in November of 1994; yours was done in May of 1995?

A. June of 1995.

Q. June, June of 1995?

The only thing that's transpired between those two dates is two more wells; isn't that correct?

A. Yes, sir.

Q. Did you have the log data from the Klein 1 as well as the log data from the Snyder 2 to incorporate into your analysis?

A. Yes, sir, I did.

Q. Did any of the log data from either of those wells cause you to change your map?

A. I mean, substantially, there was no change in the structure.

Q. Let me ask you this: If we took that data away from you, having been incorporated into your current map, would it change your map?

A. No, I would draw it similar.

Q. Okay. When you look at your isopach from today and look at Mr. Crow's exhibit, which is our Exhibit Number 3 -- it's his isopach from January -- compare for us the northern boundaries on his isopach in January with your conclusions about the northern boundary on your isopach.

A. Again, the northern boundary is very similar, within a few hundred feet of the north part of Section 33 and 34.

Q. As I remember it, the change in the Applicant's pore volume map is directly attributable to an analysis of the 3-D seismic data from which they infer an edge to the reservoir that they can see on seismic information; is that a correct characterization of it?

A. That's a lot of information in one statement. Let's break that up.

Q. All right. Talk about your understanding of what the Applicant did with the seismic data to cause that reservoir to move southerly on the hydrocarbon pore volume map.

A. As I recall his testimony, he said he -- from seismic, he picked the edge of the reservoir, the place where it tailed down, and they lost that seismic amplitude anomaly.

Q. All right. In order to have the ability to achieve that kind of interpretation, what do you have to do as a geologist? Describe how that happens.

A. Well, he would have to look at the 3-D seismic data and find the edge boundary of the reservoir, and from there he would have to draw a zero lie all around the boundary that he saw.

In addition to the zero line that's drawn all the way around the boundary, it looks to me like there were other contours that were drawn inside that boundary, that lead me to believe that there was an interpretation based on seismic.

Q. Give us a sense of the geologic components that we're dealing with here in terms of depth, distance of reservoir, and other elements, in order to make that kind of analysis.

A. To make that kind of analysis, you have to look at your seismic data, you have to tie it to your well data.

From there, you should generate velocity maps, velocity should be converted to depth, and then you have to be careful of some things.

For example, I don't know where their geophone array was. It may be at the northern boundary of their unit. If so, then somewhere inside of their unit the quality of their data will decrease. In other words, they need to have some offset on their lines in order to have good quality data within the unit boundaries.

Q. If the northern edge of the seismic data corresponds to the northern edge of the unit, what happens to the reliability of the seismic data?

A. Well, it's decreased within the unit. And again, I asked for a seismic geophone array to see where the basic data was present and couldn't get it.

You know, at about 2.1 miles into the earth, they have mapped a seismic anomaly that -- Well, for example, down here by the Speight well where they add some 30 feet of reservoir -- you know, I don't know that their data is accurate enough to put 30 feet of reservoir there.

Q. Have you had an opportunity to at least visually inspect on the computer screen some of the seismic data?

A. Yes, I did.

Q. Have you in the past worked with geophysicists in analyzing and looking at seismic information?

A. Yes, many times. When I was employed with Tenneco, we were broken up into teams and there was cross-training where I was required to go to the geophysical department for months. I've had courses in geophysical interpretation. I have worked on 3-D seismic stations. And yes, I have done that sort of work.

Q. Tell me from your perspective as a geologic expert how 3-D seismic information might be utilized in analyzing this reservoir from a structural point of view.

A. I think that it was best characterized by an earlier witness that with 3-D seismic you can find subtle seismic anomalies that can lead you to finding these phylloid algal mound buildups, and that this 3-D seismic is a good semi-quantitative tool to find those phylloid algal mound buildups.

When you get into extremely narrow interpretations of a few feet, 10 to 15 feet of reservoir, in my opinion, it becomes suspect.

Q. Would that be scientifically reliable upon which you could make judgments about distribution of pore volume, or would in your opinion it be so speculative as to not serve a useful scientific purpose?

A. I mean, obviously, it's somewhat speculative. It was testified earlier today also that at one point they thought they were going to have to have 50 feet of original reservoir, and when they drilled it out it was actually 36 feet. There's a 14-foot difference there. That sometimes there were five or ten feet more or less porosity that drilled out than they saw on their seismic.

Yeah, it's -- Within a narrow range, it's pretty speculative. It's a good semi-quantitative tool for locating an algal mound buildup.

Q. The Examiner has got the responsibility of making a judgment about hydrocarbon pore volume distribution in deciding how to organize the statutory unit.

You're an expert in geology. Give us your opinion as to what he should do with the distribution of the hydrocarbon pore volume issue. How should that be resolved?

A. It was characterized earlier that the most accurate data for finding hydrocarbon pore volume is well-log analysis, and I think that a map based on well-log analysis is the most accurate map to use.

Q. And which map would that be?

A. That would be Exhibit 7, the Snyder Exhibit 7, hydrocarbon pore feet map.

MR. KELLAHIN: That concludes my examination of Mr. Clemenson, Mr. Examiner.

We would move the introduction of his Exhibits 5, 6 and 7.

EXAMINER CATANACH: Exhibits 5, 6 and 7 will be admitted as evidence.

MR. BRUCE: Just a minute, Mr. Examiner.

CROSS-EXAMINATION

BY MR. BRUCE:

Q. Mr. Clemenson, would you get your Exhibit 5, the structure map, together with Gillespie Exhibit 4?

A. Okay.
Q. Looking at this, it seems that generally, overall, if you look at the south half, south two-thirds of the unit area, your interpretations as to structure aren't that much different?
A. Other than the northwest quarter of Section 34.
Q. But do you agree, the south two-thirds of the unit, your structural interpretations are pretty similar?
A. Well, I mean, do you want me to be right within --
Q. I'm just saying, generally -- I mean, they have a pretty big --
A. My 7550-foot contour goes through --
Q. I'm saying, look at the southwest corner of the unit. You have a pretty severe nose, structural nose, there?
A. I wouldn't characterize it as severe.
Q. You wouldn't? How would you characterize it?
A. I'd say that it's north dip into the Tatum Basin.
Q. Okay. It's certainly more severe than any nosing you have in the northeast part of the unit, isn't it?
In other words, you have a more severe structural nosing on parts of the unit, in the south of the unit, until you get to the north, and then your lines kind of flatten out?

A. The most severe structural nosing is over here outside the unit.

Q. I'm just looking at the unit, Mr. Clemenson.

A. Okay. Again -- Bring your question to me again, please.

Q. I'm just saying that isn't it true that as you go further north your structure flattens out, you have it flatten out a lot more than it's -- a lot flatter than it is in the southern part of the unit?

A. Are you asking me if my structure is flatter in the south half of the unit?

Q. In the north half of the unit than it is -- Right at the very north boundary of the unit, is your structure flatter than it is in the south --

A. Let's talk sections here.

Q. Let's talk --

A. Section 1 --

Q. Let's talk -- Let's talk north, right at the north boundary of the unit.

A. Okay. Well, that's the north --

Q. Let's take your 7600-foot line and your oil-water-contact line.

A. Okay.

Q. That's a lot flatter than, say, your 7450 line, your 7500 line?

A. You have more control right here in this southern portion. Within a very small area you have seven wells from which to contour this data.

Q. Thank you. And you did not incorporate any seismic into your structure map?

A. No, sir, I did not.

Q. Let's look at your Exhibit 6, your net-pay map. And if you want, the Gillespie Exhibit 3, which is also their net porosity map.

A. My 6 and their 3?

Q. You've got it. Now, you show the thickest part of the pay at the Speight Fee Number 1 well, 129 feet?

A. Yes, sir.

Q. And the Applicant shows it to the south of that, 160 to 140 feet?

A. Yes, sir.

Q. Could that extra feet of pay shown on the Gillespie map, could you derive that figure from seismic?

A. If you believe that you can pick 30 feet of reservoir two miles in the ground based on seismic.

Q. Could you pick it on seismic?

A. Me?

Q. Yes.

A. I don't know if that's possible, for me or anyone else.

Q. Is a map based solely on well control superior to a map based on well control and 3-D seismic?
A. That depends on the purpose of the map. If you are mapping a wide trend, long trend, where you would like to know -- Well, I will say that if you have a long trend, you would want to use some seismic data there.
Q. Generally, if you were mapping something, would you feel better if you had some seismic to go along with your well control?
A. Not always.
Q. Not here?
A. I think I answered your question.
Q. Not here?
A. Again -- Rephrase your question to me.
Q. Looking at this particular unit in this particular pool, do you feel better having just well control, or would you feel better having well control plus seismic?
A. The seismic would be a good semi-quantitative tool to help define the boundaries or the edges of the reservoir. When you get into very tight interpretation, I don't know that it's useful.
Q. Okay. Now, you said during your direct testimony that you didn't really see the seismic, you don't know how good the seismic was?

A. I didn't say I didn't see the seismic --

Q. Okay.

A. -- I said I looked at it on a computer.

Q. Okay, you weren't sure how good it was?

A. I didn't say that either. I said I didn't think that it was very good.

Q. You didn't think. I mean -- but it was -- It was good enough in this particular pool to drill 11 of 11 wells as good, economic producers, wasn't it?

A. It wasn't good enough to accurately find 50 feet of reservoir, and then you only had something less than that.

Q. Answer my question. Was it good enough to find 11 of 11 wells as good economic producers and --

A. I don't know -- I didn't drill the wells, and I don't know that seismic was used for every single well, solely, only, and that no other geologic information was used to generate a map to drill wells from.

Q. Now, on the -- Looking at your net pay map, your zero lines don't, say, go to the north half, northern boundary of the unit, they don't -- the zero line on your map does not differ hardly at all from Mr. Crow's zero line?

A. His appears to be a little more wavy. Mine's not.

Q. Okay. The main thing is that he's saying that a portion of that -- that there's reservoir there, but it's wet?

A. Are you talking about his Exhibit 3?

Q. Well, I'm just saying if you look at it --

A. His Exhibit 3 is a net porosity map, which has nothing to do with water saturation whatsoever.

Q. Okay, but if you look at their Exhibit 9 --

A. Oh, I thought we were comparing Exhibit 3, I'm sorry.

Q. Okay, all I'm saying, all I'm asking is, generally, they show their zero line to be fairly -- I mean, you can quibble with me if you want, but the northern boundary of both zero lines is pretty much the same?

A. On --

Q. On your Exhibit 6 --

A. -- Exhibit 9?

Q. -- on your Exhibit 6 and his Exhibit 3.

A. Okay, let's -- Now we're back to Exhibit 3. I'm sorry.

His northern zero line is, you know, for all intents and purposes, very similar to mine. It runs subparallel to the northern boundary within a few hundred feet, yes.

Q. Okay, that's all I'm asking.

The difference when you get into calculating the hydrocarbon pore feet then comes into how much of the northwest quarter of Section 34 is wet, how much of the net pay above three percent is wet; is that correct?

A. Let's -- Are we talking on a specific map here?

Q. You can look at whatever maps you want.

A. Help me out with your question again, I'm sorry.

Q. Okay, pull up Exhibit 9 if you want, his Exhibit 9 --

A. Okay.

Q. -- and look at your -- take his Exhibit 3, their Exhibit 9.

A. Okay. We're looking at Gillespie-Crow Exhibit 3 and this one that's labeled --

Q. -- Exhibit 9.

A. -- Exhibit 9. So -- two maps --

Q. You're basically saying the reef is there in the northwest quarter of Section 9. The Applicant is saying the reef is there in the northwest quarter of Section 34, excuse me.

A. He maps some net porosity in the northwest quarter of Section 34, that's correct.

Q. And then looking at Exhibit 9, what he's saying is that it's wet; is that correct?

A. That's what he says, that it's below the oil-water contact.

Q. Below the oil-water contact. And you don't show much of the northwest quarter of Section 34 below the oil-water contact?

A. That's correct, based on my structure map that incorporates data from wells outside the unit.

Q. You're looking at your Exhibit 6. Now, you said the best thing is well control in interpreting this pool?

A. That's correct.

Q. If you'll look in the northwest quarter of Section 4, what -- You've got this big lobe of 50 feet of net pay encompassing Snyder Ranches' acreage. What well control is that based on, to the north and to the east?

A. That's my geologic opinion.

Q. What well control?

A. Well, there's the Gillespie Number 1 Wiley that's 61 feet in the eastern half of Section 33. There's the Number 1 Klein that's 38 feet, and the Number 1 Snyder that's 41 feet.

The Number 1 Snyder well, having 41 feet, you would have to draw a 50-foot contour somewhere north of the Snyder Number 1. That's my geologic opinion.

Q. Okay. Could well be -- your --

A. That's the well control --

Q. The east boundary of the 50-foot contour line could well be moved substantially to the west?

A. I wouldn't say substantially. I don't know that -- I wouldn't move it. This is my geologic interpretation, and I would leave it like this.

Q. On your Exhibit Number 7 -- or excuse me, leave it on Exhibit 6, the Atlantic Number 1 Chambers. Did you look at the deep structure in that well, Devonian?

A. No, I did not look at the Devonian in that well.

Q. Could the Atlantic Number 1 Chambers be relatively high due to some deeper structure?

A. Are you talking structure? Do you want to talk on the structure map?

Q. Whatever you want.

A. Your question to me was, could it be high due to a deeper structure?

Q. Yes.

A. I have that well mapped low --

Q. I mean --

A. -- at minus 7592.

Q. On the Bridge Number 2 Culp well, did you look at all the well cuttings from that well?

A. No, I did not look at well cuttings in that well.

Q. At all?

A. (Shakes head)

Q. Now, one thing you said, there's not many structurally low wells out here. I think you said that anyway.

A. No, I think I said there was no well that penetrated the top of the mound facies below 7600 feet on this map.

Q. Did people used to drill these wells on a structural play? In other words, they were looking for the structural high, and therefore that may be one reason why there's not many wells out there?

A. You're asking me to speculate on what other people would do, and I don't think I'm able to do that.

Q. Looking at your hydrocarbon pore feet map, do you think a portion of the east half of Section 34, over to the east, say the west half, east half of Section 34, and a portion of Section 1 to the south, should be added to the unit?

A. You're -- I don't draw unit boundaries.

Q. Okay, but if you were drawing unit boundaries, would you add that acreage?

A. I'm going to answer your question the same way. I'm not trying to -- I'm just saying I don't draw unit boundaries. I draw maps, and I drew this map independent of any unit boundary. This is simply a unit boundary that was proposed by your client, that has been superimposed on this map.

MR. BRUCE: I think that's all the questions I have at this time, Mr. Examiner.

EXAMINER CATANACH: Mr. Kellahin?

MR. KELLAHIN: A follow-up question.

MR. BRUCE: Mr. --

EXAMINER CATANACH: Oh, I'm sorry.

MR. CREMER: I want to ask a few questions.

EXAMINER CATANACH: Yes, sir.

EXAMINATION

BY MR. CREMER:

Q. Mr. Clemenson, in looking at the exhibits that have been introduced by Gillespie, is it your opinion that they've honored their well data in preparing those maps?

A. Well, I think if we're -- I mean, that's a -- There are many maps, a lot of well data. If you want to talk about a specific one, or talk about all of them in general or --

Q. Well, is there anything that you can point to there that shows that they did not honor the well data that they had in preparation of those maps?

A. If I were mapping this, which I did, I would use additional well data outside the unit boundaries to help me to determine how I thought the trend would run through this unit area, and so I would use more data than what they have to help me --

Q. Okay. But you can't --

A. -- control points.

Q. Right. But that would still call for speculation, and it would just be another control point that you would use, and you can't point to anything on those maps that says they did not honor the well data that they had in mapping those structures?

A. If you look at their structure map, I personally don't see a reason to bring this minus 7600-foot contour in that strong of a nose that far south.

In fact, you're having to start to crowd your contours up between minus 7550, to right -- on the State S tract, in the east half of the west half, about midway up, the minus 7550-foot contour is very close to the minus 7575 contour, which is very close to the minus 7600-foot contour, and --

Q. Well, but that's --

A. -- all start crowding up right there, and I don't see any geologic basis for that.

Q. But you don't see any geologic basis to indicate for certain that that's incorrect?

A. Yeah, I do. When I take well data from outside the unit and incorporate it into a map, I do see directly conflicting data in that no well has penetrated the top of the reef below minus 7600, north of the line that is the north line of Section 34 and 32.

Q. Okay, so your testimony, then, is that you know for certain that the structure map is wrong?

A. My testimony is that my structure map is the most accurate structure map.

Q. Would you say that seismic data is useful for determining structure, apart from well control, away from well control?

A. Again, seismic is a good semi-quantitative tool to locate velocity anomalies that will help you to pick out these phylloid algal mound reefs.

Q. Okay, so --

A. You know, can -- you're --

Q. -- when you don't have the well control -- Let's say when you don't have the well control available --

MR. KELLAHIN: Objection, did witness finish your answer? Did you get to finish your answer?

THE WITNESS: When you pick a seismic reflector two miles in the ground, you have to know the quality of your seismic data to know whether or not you're accurate to within 30 feet or 50 feet, and that's what we're talking about on this map. So it's quality of seismic data.

Q. (By Mr. Cremer) Right, okay.

A. And that is indeterminate.

Q. If you don't have well control -- If you have an area where there is no well control, is seismic data generally useful for determining structure?

A. In the absence of well control, seismic may be a useful semiquantitative tool to get you in the ballpark of drawing a structure map or -- Have I answered your question?

Q. Okay, that's fine, yeah.

And you testified that down in the central portion of the unit where there are several wells put together, you are very comfortable with the well control that you have down there, because there's several wells in close proximity to each other?

A. Well, not only that there are several wells in close proximity to each other, but those wells are close to each other structurally.

I mean, I can point --

Q. Okay.

A. -- one place right here, between the Hamilton Number 4 and the Hamilton Number 3, you have to draw those structural contours wider to honor your data.

Q. So you're much more comfortable about your interpretation in that area of the unit?

A. I mean, if you want to talk in terms of, you know -- if you had a well spot on every 40 acres, you know --

Q. -- you could do a better job of mapping?

A. -- you could probably do a better job of mapping, if you had all that data.

In the absence of that data, you should use as much data as you can, that being wells outside of the unit boundary also.

Q. Okay. Are there any wells that you know of to the north of the unit boundary -- I mean directly to the north of that -- the oil-water contact area, that you used for well control in this situation, besides the -- this Atlantic well, Chambers well, and this BTA well over here?

A. You know, what I have on here are the maps that -- are the wells that I saw spotted --

Q. So there aren't --

A. -- in both sections.

Q. -- any wells up to the north of there, that you --

A. Well, not in Section 30, 29, 28, 27 or 26.

Q. Okay.

A. Further north than that, I don't know.

Q. So in other words, you have a lot less well control to rely upon as far as the oil-water contact goes in that portion of the unit area, than you do down here in determining the mapping and the pore-feet volumes in the middle of the --

A. Again, to the contrary. To determine the oil-water contact, I used wells to the east and the west of the unit boundary, and the trend that was established between those wells across a five-mile east-to-west swath helped me to determine where this minus 7617 contact is.

Q. Okay. Now, that's a five-mile swath, as you've said, with no additional wells in between that five-mile swath?

A. There's wells inside the unit between those wells.

Q. But not up in that -- up north of the boundary line there?

A. Again, no well penetrated below minus 7600 feet.

Q. So it's very possible, then, that the oil-water contact could be where you have it based on the Chambers well and based on the Townsend well, and it's certainly possible that it could do exactly what it does on Gillespie's Number 9 exhibit, and not what it does on your exhibit?

A. In my opinion, that's just highly unlikely, that you would have a big nosing saddle across the state lease, down onto the Snyder lease, because you have data outside the unit that dictates to the contrary.

Q. It's unlikely, but it's possible?

A. It's very unlikely, is my answer.

Q. Is it possible?

A. My answer is --

MR. KELLAHIN: Objection to the speculative question.

MR. CREMER: I don't have any further questions, Mr. Examiner.

MR. KELLAHIN: No, sir.

EXAMINER CATANACH: I've got a couple of questions.

EXAMINATION

BY EXAMINER CATANACH:

Q. The additional data that you used outside the unit you're talking about, the Chambers 1 and the Culp Number 2; is that correct?

A. I'm talking about wells outside of the unit that I used as additional data, would be the Atlantic Number 1 Chambers in Section 26, the Bridge Number 2 Culp in Section 34, going south to there, the Ferran Number 1 Roose, additionally the Amerind Number 1 West State, the Mitchell Number 1 Bear, the BTA Number 1 Townsend, and then these wells further south in Section 3, the Yates Daisy, the Mesa Townsend and the Bridge Chevron.

Those are wells that are outside of the unit boundary that I used to help me map this trend.

Q. Do you know if these wells were not utilized by the Applicant?

A. All I can say is, you know, I see the Bridge Number 2 Culp on their map and this Amerind State well, but I don't know that the Applicant used -- apparently they didn't use the other wells.

Q. If you were to look at the Applicant's Exhibit Number 4 and follow their minus-7600-foot contour line, couldn't that contour line honor the data from the Atlantic Chambers Number 1?

A. It's possible, but in my geologic opinion it's unlikely because you have wells to the west, wells here in the middle, in the unit, and then you go to the wells to the east, and they all establish a, in my opinion, well defined structural trend, or especially a trend to put in the minus-7600-foot contour.

Again, no well ever penetrated below minus 7600 feet, the top of the reef. And those wells are some 300 feet north of the section line that divides 34 and 27 and 28 and 33.

Q. In the southern portion of the Snyder tract, it looks like a pretty well defined nosing structure there, and yet you map it flattening out to the north. Is that due to the -- mainly to the Chambers well data, or -- Well, let me just ask you, why does it flatten out so much?

A. You can see that there are several areas within the unit boundary that flatten out, if you will. For example, between the Hamilton 1 and the Hamilton 2, it gets very flat. But between the Hamilton and the Speight, it's fairly tight.

My placement of the minus-7600-foot contour line is my geologic interpretation. It's based on the entire trend, not just the Atlantic Number 1 Chambers well, but BTA Townsend, the Mitchell Bear, the Klein well, all the wells that are the furthest north, also being the furthest structurally downdip.

Q. Do you feel like you could have done a better job mapping this structurally if you would have had the 3-D seismic data?

A. Personally, I looked at the 3-D seismic data. I thought it was pretty shadowy, and I would not use it.

EXAMINER CATANACH: I have nothing further of this witness. He may be excused.

MR. KELLAHIN: Yes, sir. Call Terry Payne.

TERRY D. PAYNE,

the witness herein, after having been first duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. KELLAHIN:

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

A. Terry D. Payne, and I'm a petroleum engineer.

Q. Where do you reside, sir?

A. Austin, Texas.

Q. On prior occasions have you testified before the Oil Conservation Division and qualified as a petroleum engineer with expertise in petroleum reservoir engineering?

A. Yes, sir, I have.

Q. Summarize for us your education and employment experience.

A. I'm a 1985 graduate of the University of Texas in Austin, with a bachelor of science in petroleum engineering.

At that point I went to work for Conoco, worked for them for about a year in south Texas, then I went to work for Chevron in New Orleans as a production engineer and reservoir engineer for about six years, and then was employed by Platt, Sparks & Associates, my current employer, as a consulting petroleum engineer in 1991.

Q. Does your experience and knowledge, as well as your application of your skills include log analysis?

A. Yes, sir, it does.

Q. Do you and your consulting firm, Mr. Platt, have the ability to analyze logs and reach conclusions about porosity based upon that log analysis?

A. Yes, we do.

Q. Are you regularly and frequently hired as consultants to make maps and generate conclusions and opinions about hydrocarbon pore volume distribution in reservoirs?

A. We are routinely hired in that fashion. We typically work with a consulting geologist such as Mr. Clemenson to physically make the maps. We provide the data, and they do the interpretation and the contouring of that log-analysis data.

Q. And is that in fact what occurred here between you and Mr. Clemenson?

A. That's exactly what occurred.

Q. As a result of that work, do you now have conclusions about the distribution of the hydrocarbon pore volume in the reservoir?

A. Yes, sir, we do.

Q. Have you applied conventional engineering methodologies and calculations to determine the accuracy of the distribution of that hydrocarbon pore volume?

A. Yes, we have.

Q. There are conventional, classic engineering ways to validate that pore volume map, are there not, sir?

A. There are.

Q. In addition, have you studied the production plots and profiles of all the wells in the pool?

A. Yes, I have.

Q. Have you made an analysis of all the logs in the well -- of logs of wells in the pool?

A. Yes, we have.

Q. In addition, have you studied and made yourself familiar with the tract participation formula that the Applicant has proposed to the Division?

A. Yes, sir, we have.

Q. And you are aware of and know the impact of that allocation formula in terms of assigning a participation factor to each of the tracts, don't you?

A. Yes.

Q. Based upon that study, do you now have recommendations for adjustments in how equity is established in terms of assigning relative value to each tract in the unit?

A. Yes, we do.

Q. Summarize for us, Mr. Payne, whether or not in your opinion there is sufficient information from an engineering perspective upon which to make conclusions about tract participation in this unit based upon the hydrocarbon pore volume distribution that Mr. Clemenson has prepared.

A. We definitely do have adequate information to determine hydrocarbon pore volume, its distribution in the reservoir.

And more importantly, it is time in this reservoir's life to impose secondary recovery operations, and we do have enough information to do that at this time.

MR. KELLAHIN: We tender Mr. Payne as an expert petroleum engineer.

EXAMINER CATANACH: Mr. Payne is so qualified.

Q. (By Mr. Kellahin) Let's look at some of the data that you've gathered.

A. Okay.

Q. If you'll start with Exhibit Number 8, identify and describe what you have shown the Examiner.

A. Exhibit Number 8 is a binding that contains production data from the West Lovington-Strawn Oil Pool.

The first page of this exhibit shows the pool total. We show the oil production line in green, the gas production line in red, and the resulting GOR in blue.

And you can see that the pool GOR initially was in the 2200-standard-cubic-feet-per-barrel range, and it's now down in the range of about 1600 standard cubic feet per barrel.

This data was obtained from public record sources. It's production data for the entire pool.

We also do have the production information, same type of display, for each individual well.

And then we also show the tabular listing, the backup data, towards the back of the binding.

Q. How have you utilized this information?

A. Basically to look at the GOR history of the pool. Again, we mentioned that it started out at about 2200. It's substantially lower than that now, it's about 1600.

And it does also appear, we've heard testimony today that the reservoir has not reached a critical gas saturation. The GOR has actually increased on individual wells, and it does look like a gas cap is forming. So we probably have exceeded the critical gas saturation in this field.

Q. Why is that of any importance?

A. Well, to basically understand what's happening in the field and to understand why gas injection will work and why it will be beneficial, we have to understand the mechanism that's actually operating in this field.

Q. This is a solution gas drive reservoir?

A. Solution gas drive and gravity drainage, yes.

Q. Okay. Let's turn to the next basic information booklet.

A. Okay.

Q. If you'll look at Exhibit 9, identify and describe the type of information that's contained in this display, and then we'll talk about the details.

A. Okay. Exhibit Number 9 is a packet of information on the detailed log-analysis calculations that we have done on each well that penetrates the pool.

On the summary pages we list the results. Just going across, we have each individual well, calculated net pay, porosity, water saturation, and the resulting hydrocarbon pore volume, which is net pay times porosity times one minus the water saturation -- or the oil saturation.

We then compare that with the hydrocarbon pore volume numbers that were generated off the Gillespie exhibit through their analysis.d

And we also show at the top of the page that we are both using R_w of .052, from the DST on the Klein Number 1.

Q. What else is contained in this exhibit book?

A. Okay, moving towards the back of the booklet, the next section is a display of results. We have some color-coded charts.

We probably should have numbered the pages, but the third page of the booklet is the display results for the Earnestine State Number 1, and we'll briefly describe what each of these show.

On the first column we show the gamma-ray information. And the brown color is the -- indicative of reservoir-quality rock, whereas the gray is the shalier sections.

Moving across, we show the perforated interval of each well.

And then the red column on the right side of the depth track are the pay intervals or the net footage intervals that meet the net pay criteria that we have applied to this analysis.

Moving on into the water saturation information, the next column, we have water saturation going from zero to 100 percent, and the green is indicative of hydrocarbon saturations.

And then the last column on the page is the calculated porosity. And then we show where the porosity exceeds the cutoff of 3 percent, and we have shaded that in red. And again, if the calculations meet the porosity cutoff and the water saturation cutoff, it's indicated as net pay on the depth track as the red bar.

And then these are the results that are tabulated on the front page of this exhibit.

Q. When we move -- We'll come back to this section, but when we move past this section where you say "User Defined Log", you get into another section behind the next blue tab in which it still says "User Defined Logs", but you have shown the information in a different way.

A. Yes, what we have behind the next blue tab is what we have labeled "Raw and Corrected Resistivity Data".

And again, we start off with the gamma-ray track and then the depth track, but the information that we're displaying here is the shallow, medium and deep resistivity curves, exactly as they appear on the log. This is digitized information, just the way Gillespie has done their analysis. The only thing that we have added here is the true resistivity or the deep resistivity, corrected for the effects of invasion.

Q. Let's stop for a moment and put this in context. When you're going through log analysis, one of the items to address is this water-saturation component; is that not true?

A. That is true.

Q. When you're trying to determine the hydrocarbon pore volume distribution in the reservoir, looking at log analysis, give us a short summary of how this is meaningful to you when you're trying to look at hydrocarbon pore volume.

A. Okay. Basically, our analysis procedure is very similar to Gillespie's procedure. We used water saturation as the square root, R_w over porosity squared, times R_t.

We are both in agreement on R_w. However, we do have some disagreements over R_t and over the porosity value to use at each half-foot interval.

Our technique is the same as far as digitizing; we digitize it every half foot.

But the two areas where we differ is in what we use for true resistivity and what we use for porosity.

Q. All right, let's stop for a moment. We'll come back to those items.

What do you do with the water saturation as a component of the calculation to get you this pore volume value adjacent to each of the wells that Mr. Clemenson then has contoured?

A. Okay, well, back on the first page of the exhibit we do show the hydrocarbon pore volume. And again, it is net pay times porosity times one minus the water saturation. So if we disagree on water saturation, we're going to disagree on the hydrocarbon pore volume.

Q. All right.

A. But it is a direct component of that calculation.

Q. And there is in fact a direct disagreement over the water saturation value?

A. That's correct.

Q. The first disagreement is over R_t?

A. Yes.

Q. Describe for us what Mr. Nelson did and what you think is the correct way to do this.

A. Well, they have assumed that the resistivity reading is in fact representative of true formation resistivity, or R_t.

However, these wells were drilled severely underbalanced, and you can clearly see on the resistivity curves that there is an invasion profile. The shallow gives one reading, the medium gives another, and the deep still a third.

If they all laid on top of each other, invasion wouldn't be a problem. But obviously invasion has occurred here, and to get to R_t you must make the correction.

Q. How do you make a correction to get to R_t?

A. Well, just like QLA2, our log analysis program is Hydrocarbon Data Systems, and it is a correction that is inherent in that program. But it basically comes from the Tornado Invasion Charts by Schlumberger and the other log manufacturers.

But it is a correction. You take the ratios of the resistivity curves and enter into the chart, and it will give you a multiplier to apply to the lateral log deep reading, which you can then use to determine R_t.

Q. Is there an illustration on the log data that you've presented where we can visualize the difference between your method and Mr. Nelson's method when we get to the R_t discussion?

A. This section of the display that -- The raw and corrected resistivity data does in fact show all three curves, along with the corrected R_t version. It shows the three raw curves and the corrected R_t.

Q. All right. You're looking at this colored page of the display?

A. Right, and I'm looking at the Earnestine State Number 1, which is the first well in that section.

Q. All right. Each of these lines on the right-hand side of the log is color-coded?

A. That's correct.

Q. Define each of them for us.

A. Okay. The green is the shallow resistivity reading in each case, the blue is the medium resistivity reading, and the red is the deep resistivity curve.

Q. For example, on the Earnestine State well, Mr. Nelson would have used the red line?

A. That's my understanding of what he did, and I believe that was his testimony this morning.

Q. All right. Where does the true R_t lie?

A. It's actually a higher resistivity reading than the lateral log D.

Q. For purposes of this well, when you get to a calculation of porosity, then, what effect does that have?

A. Water saturation?

Q. Yes, sir.

A. It has an effect on the water saturation calculation. It actually decreases your calculated water saturation when you use the corrected resistivity versus just the reading off the log.

Q. If you decrease your water saturation, what does it do to your calculation of pore volume?

A. It would increase it.

Q. Okay. Take us over to the Hamilton well. I think it was the Hamilton 3, was it? I think it was the Hamilton 3.

A. In the porosity section?

Q. Yes, sir.

A. Okay.

Q. I've skipped ahead.

A. Okay.

Q. On R_t now, if you correct as you have done to get the true resistivity, it is going to ultimately have effect on the calculation of S_w?

A. On water saturation and resultingly on hydrocarbon pore volume.

Q. All right. R_w, there's no disagreement; you and Mr. Nelson have used .052?

A. That's correct.

Q. There's a difference between you on R_t?

A. That's correct.

Q. There's also a difference on porosity?
A. That's correct.
Q. Mr. Nelson was using the density curve on the log, and he was using a multiplier of .85?
A. Yes.
Q. That gas-effect discussion we had?
A. Yes.
Q. All right. You and Mr. Nelson are going to disagree on porosity, aren't we?
A. Yes, we are.
Q. All right. Show us that portion of Exhibit Number 9 that has this information in it.
A. Okay, it's the final section of this package. And again we have the Earnestine State Number 1 listed as the first well.

And what we show on this display, again, moving from left to right, is the same gamma-ray information, the same depth track.

But as we move to the porosity section, we show the neutron curve in green, we show the density porosity curve in red. Both of those are raw data right off the log. And then we have the calculated neutron density porosity in brown.
Q. All right. Mr. Nelson has used only the density plot or the density curve on the log, didn't he?

A. That's correct.
Q. He's ignored the neutron curve?
A. Yes.
Q. He then takes the density curve, and he has it multiplied by .85?
A. Yes.
Q. Now, what does .85 mean to you?
A. Well, it's an attempt, it looks like, to correct it to what they see on the core data, but it's an arbitrary multiplier.
Q. Why is that?
A. Well, it sounds like he's attempting to compensate for a gas effect.
However, like we just pointed out -- and I think also in his testimony he mentioned that it was based on GOR. However, the field GOR started out at 2200. It's currently at 1600.
If you're going to apply a multiplier based on GOR, you can't use a consistent multiplier all across the board. It would have to be varied on GOR. If that's what it's because of, you're going to have to vary it as GOR varies.
What he's done is just ignore the neutron data, and we chose not to do that.
Q. How, then, did you go about determining the

porosity value for the water saturation calculation?

A. We used the average of the neutron density curves to come up with a calculated ϕnd, which is a standard calculation, cross-plot technique.

Q. If you're using a lower porosity value in the water saturation calculation, what does that do to your ultimate pore volume calculation as to that well?

A. A lower porosity value is going to decrease the hydrocarbon pore volume.

Q. Correspondingly, higher is going to increase pore volume in the tract that's got that well -- or at least for that well?

A. That's correct.

Q. All right. Having determined the correct water saturation, what then did you do?

A. Well, moving back to the very first page of this section, through that analysis, and as displayed on the plots, the visual aids in the first part of the handout, through that analysis we were able to calculate net pay, porosity and water saturation at each half-foot interval for each well in the pool and, and then from that information calculate the resulting hydrocarbon pore volume.

Q. All right. When I read across the first row on page 1 of Exhibit 9 and look at the Earnestine 1 well, we've got net pay, porosity, water saturation, and then it says hydrocarbon pore volume.

A. Yes.

Q. Is that the value that in your opinion is the correct value for hydrocarbon pore volume for that well?

A. Yes, it is.

Q. What's the next column?

A. The next column is a display of the results of Gillespie's log analysis.

Q. For which you believe it's incorrect?

A. Yes.

Q. And it's incorrect as to all the wells?

A. Yes.

Q. When we look at the final column, then, to the right on this page, what does that show?

A. It shows the difference -- percentage difference in hydrocarbon pore volume between our analysis and Gillespie's analysis.

Q. Do you have a copy of the Hamilton Federal 3 log there, Mr. Payne?

A. Yes, sir, I do.

Q. Okay. I show you what I've marked as Exhibit 10. Identify for me what I have handed you as Exhibit Number 10.

A. Exhibit Number 10 is a listing of information that was provided to us by Mr. Scolman and Mr. Nelson when Mr. Clemenson and myself went to Dallas.

It was represented to us at that time that this was the information that they were using to calculate their hydrocarbon pore volume on each of the wells.

This particular piece of data is for the Hamilton 3, and if we turn to the very last page of this exhibit, the far right-hand column is their calculation of hydrocarbon pore volume on a half-foot basis, and then it sums to 5.5973, or what was plotted on their map of 5.60.

So this is the information that was given to us when we went to Dallas, representative of their log analysis work on the Hamilton 3. And it did match the map that they were representing at that time.

Q. All right, sir. What's the problem?

A. Well, we asked Mr. Nelson this morning if he had changed any of this information in his current interpretation of the hydrocarbon pore volume on this well, and he testified that he had not.

The problem with this information is that if you look down at a depth of 11,561, column number 2 of this information indicates a density porosity of .1127. And the way they do their log analysis is, they -- that is the number that has been scaled down by .85. So if we were going to find out what was truly read from the log, we would divide that number by .85 -- Going through a lot of steps here, but it would be point -- about 13 percent.

However, when we discussed this this morning, the log at that depth actually reads about 8 percent.

Q. Do you have a copy of the log of the Hamilton 3 well in front of you?

A. Yes, I do.

Q. When you read down on the -- not the initial run, you have to go to the second one, I think.

A. Yeah, there -- We'll explain what's happened here. But at 11,561, if you look at the repeat section of this log, you actually read about -- just under 8 percent. That's as Mr. Nelson testified this morning.

However, if you look at the main pass of this log, you can see -- The first thing that jumps out at you is the tension curve. Obviously, the tension is increasing significantly at this point, the tool is obviously stuck in the hole, and at 11,561 you read about 13-percent porosity.

So on -- And the 13-percent number is what agrees with what they've used in their analysis. However, that number clearly is meaningless because the tension curve is -- it's --- The tool's stuck, it's not moving.

And if we look down at the repeat pass, the true density porosity is about 7 percent. But again, in their analysis they've used 13 percent, they've used the wrong number.

Q. All right. When we look at the spread sheet which is Snyder Exhibit 10 and look at 11,561 at that depth, the next column over is labeled DPHIA. Is that a true measurement of something, or has that been calculated?

A. That's a calculated number. They've taken the roughly 13-percent number that you read from the log on the repeat section, which is invalid -- I'm sorry, on the main pass, which is invalid. They've multiplied that by .85 to get this resulting .1127.

Q. All right. If you have read it correctly, the porosity correctly on the repeat pass, at this depth you have 7 percent?

A. That's correct.

Q. And if you use his method and multiply 7 percent by that gas effect, .85, you're going to come up with a smaller number than .1127?

A. What you're going to come up with is about 6 percent, which, if you look at the numbers right above this depth, that is the value that you're getting.

And the reason for that is, the main pass of the log stops at that depth and they have gone to the repeat section to pick up the correct data.

However, at 11,560.5 they're using the main pass of the log, and the porosity is off by a factor of 2. And the resulting calculation of hydrocarbon pore volume on this well is significantly too high.

Q. As a result of that error, has pore volume been added to the Hamilton tract that should not be there?

A. Undoubtedly it has.

Q. Have you corrected for these mistakes?

A. Yes.

Q. So when we look at the log analysis that you have completed and have calculated, then, the hydrocarbon pore volume value for each of those wells, that is correct information that Mr. Clemenson had when he did the contour map that's Exhibit Number 7?

A. That's correct.

Q. Okay. Would you recommend using the Applicant's hydrocarbon pore volume map as a way to resolve the equity for the tracts under this unit plan?

A. No.

Q. Why not?

A. It's inaccurate.

Q. Okay. Are there other places where the log analysis was inaccurate?

A. Well, that error was carried on down significantly in this same well. You can see those numbers of 12 percent. Most of those are not accurate. No, I'm sorry; I'm saying 12, but it's 11-point-something percent.

Most of those numbers are not correct. So in this well there are a number of intervals that are incorrect.

And furthermore, this R_t number, which is column number 3, is the deep reading off the curve, and that has not been corrected for invasion. So that's also incorrect.

Q. All right. Apart from the problems with the log analysis on the Hamilton 3, you and Mr. Nelson still disagree on what he used for R_t and what he used for porosity?

A. That's correct, yes.

Q. Let's turn now to a different topic. I show you what is marked as Exhibit Number 11.

Separate and apart from Mr. Clemenson's map, is there a widely accepted engineering method by which you can determine what the original oil in place is for this area?

A. Yes, and the best indicator of what the oil in place is in this field are material balance calculations. And that's what we've done here, to make sure that our material balance calculations agree with and tie to Mr. Clemenson's hydrocarbon pore volume map.

And simply because the -- The wells only penetrate a finite area of this reservoir, we only have glimpses into what's going on down there.

However, as we all agree, this reservoir is in communication from one side to the other. There are no significant pressure gradients across the field. And the pressure-volume relationships between the reservoir fluids is the best indicator of what the oil in place is.

Q. Give us a quick summary of what you've done on Exhibit Number 11.

A. Okay. There's a lot of information on this page, but basically the answer is contained in about the middle column, the first row -- it's boxed -- and it's that the oil in place in this field is 11,655,000 barrels of oil. Again, it's about the middle of the page, and it's boxed, the first line.

Q. Well, how do you know that?

A. Well, we have an abundance of pressure and production data that we can look at in this field. We also have a PVT survey, so we feel pretty good about the production volumes, how the pressure has responded to those production volumes, and how the oil and gas behaves under that pressure change in the reservoir.

Basically what we show here -- What we've tried to do is to determine how much oil, gas and water is remaining in the reservoir, convert it to reservoir barrels, and compare that volume, if you sum those three components, compare it to the calculated pore volume. And so long as those numbers are in agreement, then we have defined the pore volume properly.

And in this calculation, we have the ability to alter the pore volume. It's an input number; we have the ability to alter that. Obviously, if we put in the wrong pore volume, the resulting oil in place, gas in place, water in place, is going to be incorrect, and it's not going to respond as the reservoir pressure has indicated it has responded.

So what we are ultimately trying to do is zero out the far right-hand columns, the volume difference, which is the pore volume minus the oil, gas and water volume. And so long as that difference is zero, then we have defined the correct pore volume and resulting in the correct oil in place, gas in place and water in place.

Q. So why is that important?

A. Well, we have to honor the data that we know exists. These are facts that we know about this field. We have to honor this information if we're going to characterize or describe the oil in place. We have to.

Q. When you talk about material balance, what are you balancing this information against?

A. It's essentially balancing fluid withdrawals with pressure change.

If we -- Again, we do know exactly how much fluid has come out of the reservoir. By defining the pore volume we define the oil in place. We know how much oil has come out, we know how much gas has come out, and there has been no water production. So we know the volume that those remaining fluids take up in the reservoir. We know the reservoir volumes that each of those fluids take up.

And when that is in agreement with the pore volume, we have balanced the data and we have done a material balance on the field.

Q. Have you taken Mr. Clemenson's pore volume map as he has constructed it to see to what degree it agrees with your 11.655 original-oil-in-place number?

A. Yes, if we planimeter Mr. Clemenson's hydrocarbon pore volume map -- We'll show you here in just a minute, but it's 11,688,000 barrels, which is less than a .3-percent difference. And that's certainly within the tolerance that we can measure any of this information.

Q. What does that mean?

A. That means that our material balance information is in agreement with the hydrocarbon pore volume map, which -- The story goes around. The information has to match.

Q. Then when you're making judgments about each tract's pore volume share in the reservoir, you have validated the accuracy of Mr. Clemenson's distribution of that pore volume?

A. Combined with accurate calculations of hydrocarbon pore volume for him to then contour with, that does validate his contouring, yes.

We might add that there's -- 11.7 million barrels is close to what we have here. There's really not a huge disagreement over the oil in place in the field. It's the distribution of it.

Q. All right. Let's turn now to what we've marked as Exhibit 12. Describe what you're doing here, Mr. Payne.

A. Okay. Mr. Crow testified this morning that the goal of our -- or his proposed participating formula -- Let me back up.

The goal of his proposed participation formula was essentially to compensate for the tracts that have not had as much production, give them a slightly higher share of the oil in place or of the production than those tracts that have not either enjoyed a well on them to date or have had lesser production. So the goal of the formula is to essentially equalize recovery as a percentage of oil in place.

For instance, when the field oil in place is at some number -- I'll say 30 percent -- that each tract would be at 30 percent. That is the goal of his formula, is at some recovery that all tracts equalize with the field recovery.

However, when we've looked at that here, is exactly when that's going to occur under the proposed formula.

Q. All right, let's stop for a second. The basic concept is to distribute to each tract their proportionate share of the original oil in place?

A. That's correct.

Q. That's the premise we're starting with under the participation formula --

A. Yes.

Q. -- is that rather than well deliverability, current rate, whatever it is that might have been utilized in the formula, we're using original oil in place as a base component for distributing equity; is that not true?

A. Not only is it a basic component, it is the only component. Oil in place is the only component in this formula.

Q. All right. Is the basic concept of the formula one where all tracts, at the end of the life of recovery, will have achieved their relative share of that recovery based upon the original oil in place?

A. That was my understanding of his goal, but as this spreadsheet here shows, that will not happen under this formula.

Q. All right. To achieve that equity for those tracts that already have wells producing and have generated a cumulative number, because of the chronology of events there will be some tracts that are ahead of others in terms of oil recovery; is that not true?

A. That is correct.

Q. And so the formula would reduce those tracts' share of remaining oil recovery so that the other tracts could catch up?

A. That's correct.

Q. Under the Applicant's proposal, show us what's going to happen.

A. Okay. What we show here is the Applicant's original oil in place, starting at the top of the spreadsheet, of 11,933,000 barrels.

The next line down, we list each of the tracts. Below that we list the oil in place assigned to each tract by the Applicant. And below that we list the participation percentage that they have proposed for secondary recovery operations.

And if we stop right there and then concentrate just on the first five columns of the spreadsheet, it might be easier to understand what we're showing here. But what we show in the first column is cumulative field production, and the first line is the present production of just over 1.3 million barrels.

The next column is the percentage of oil in place, original oil in place in the field, so the field is at 11.2 percent recovery of the oil in place.

Moving over to the next column, we show that for the Snyder tract it has been credited with 27,000 barrels of production, which is 3.8 percent of the oil in place on the Snyder tract, and resultingly, we are 7.4 percent behind the field. The Snyder tract is one of the tracts that has not enjoyed as much production as others, and has a corresponding lag behind the field recovery.

Q. As we read across the spreadsheet, if it's a positive percentage, it means that at that point in time, that tract is behind?

A. That's correct.

Q. And if you find in that column where it says percentage lag behind, if it's a minus percentage, it means that tract at that particular time is ahead?

A. Yeah, that's correct. And if we move over from the Snyder 3 tracts to the Hamilton tract, for instance --

Q. That tract is one where it's overproduced its relative share under the formula?

A. That's correct. The Hamilton tract has had 638,000 barrels produced from the tract, which under the Applicant's distribution is about 18 percent of the oil in place under that tract. It's already produced almost 20 percent of the oil under that tract, whereas the field total is just at 11 percent, and resultingly, it is -- it's not behind the field, it's actually ahead of the field by 6.5 percent. And you see the same type of relationship as you move across the spreadsheet.

Q. All right. Under the Applicant's proposal, if you assume 100 percent recovery of the original oil in place in the unit, will the tract's equity ever balance when you look at one tract to the other?

A. That's the only point that they will ever balance under this formula, is at 100 percent recovery of the oil in place.

Q. Is that going to happen, Mr. Payne?

A. You said earlier anything is possible, but I've never seen that. I don't think that will happen, no.

Q. Let's use a 30-percent recovery. I think we heard that range from Mr. Crow this morning as a probability, that 30 percent with primary and secondary --

A. Okay.

Q. -- was a goal to look at.

If we find on the first column or -- yeah, the first column on the spreadsheet, on the left, read down, it says in the future, if we look at the second column over, it says 30 percent. Are you with me?

A. Yes.

Q. What happens then?

A. Well, I'm definitely with you. I hope everyone else is.

Q. All right. Well, you do it for us.

A. Okay. No, not that you can't explain it. There's just a lot going on, on this spreadsheet.

But what we've done is predict what's going to happen in the future using the Applicant's formula. And when the reservoir is at 3.58 million barrels of recovery or 30 percent of the Applicant's oil in place, if we move across here, the Snyder tract has only been credited with 24 percent of the oil in place on the tract. So although their stated goal is to equalize the recovery, this formula doesn't achieve it at the recovery factor that they're predicting for the reservoir.

Q. It's still behind by 5.8 percent?

A. We've gone from the 7.4-percent lag that we're at now -- We have moved forward some, to where we're only 5.8 percent behind the field. But we're nowhere close to being caught up.

And again, tracts that were ahead stay ahead, and tracts that were behind stay behind.

Q. How are we going to fix this?

A. Well, we have a formula to do that.

Q. All right, sir. If you'll turn to your Exhibit Number 13, would you identify and describe that display?

A. Okay, this might answer some of the questions that were brought up earlier this morning.

What we list here is the tract number, the tract name, the original proposed tract participation, which was done, I believe, as late as December of 1994 and January of 1995, and then we show the current proposed tract participation, which is current as of today. And then we show the percentage change for each tract.

Q. All right, let's just take an example. If you come down the spreadsheet and look at tract 6, that's the Snyder tract?

A. That's correct.

Q. Under the original proposal, it has what participation percentage?

A. Under the original proposal, it was going to participate with an 8.6-percent factor. However, the current proposed factor is only 6.3 percent, and it's a decrease of almost 30 percent.

Q. All right, sir. And then read down to tract 1. It's the Hamilton tract?

A. Yes.

Q. What happens under the original proposal?

A. The Hamilton tract originally was going to participate with a factor of 17.5 percent. Now it's proposed to participate with a factor of 28 percent. It's an increase of 60 percent.

Q. What's the next page of the display?

A. The next page is simply a color-coded display of the same data. It's just a little bit easier way to see the information and the relative impact of what we're talking about.

What we show here are, the red bars are the original proposal that we had just a couple of months ago, and the current proposal, which are the green bars, and this percentage of the production accredited to each tract.

We have also added some blue dots on the display which indicate where Mr. Crow has a personal interest in these tracts, and it's the five tracts on the far right, the Hamilton, the two Wiley tracts and the two Klein tracts.

Q. All right, sir. And the last page of the exhibit?

A. The last page shows a lot of the same information, but what we do here is quantify the difference and show the percent difference in the two proposals.

What this display shows is that although the State T picked up some participation percentage, the three big winners in this change are the Hamilton tract where we drilled no new wells, and the Klein A and the Klein B. The Hamilton tract, which has got more oil in place than any other tract in the unit, was increased by 60 percent.

We also see that the tract that was affected the most -- least favorably or which was reduced the most was the Snyder tract, which was dropped -- I said 30 percent before. It's about 27 percent.

Q. When you look at our Exhibit 7, the hydrocarbon pore volume map, and compare it to Exhibit 9, which is the Applicant's pore volume map -- As a reservoir engineer, Mr. Payne, when you're looking at the distribution of reservoir pore volume between the tracts on the two different maps, identify for us where the greatest degrees of change are occurring and why.

A. Well, comparing their map to our map --

Q. Yes, sir.

A. -- there are -- we talked about it earlier -- there are some large changes on the Speight tract where they have contoured up and above their existing well control. They have a lot of hydrocarbon pore volume there.

And also on the Hamilton tract, they have significantly more hydrocarbon pore volume than we contour. We talked about some of the things that are going on there with the log analysis.

But those are the two main areas, with the exception of the Snyder tract, where their interpretation of the oil-water contact brings it further onto our acreage, onto the Snyder acreage.

Q. Let me have you direct your attention to what I've marked -- I'm going to go to another display, Mr. Payne. It's Exhibit 14. All right, identify and describe for us Exhibit 14.

A. Okay. Exhibit 14 is very similar to our previous Exhibit 12. What we do here, though, is propose a two-factor participation formula which will achieve the stated goal of the previous formula and actually allow equalization of recovery for the various tracts at a realistic ultimate recovery.

And then participation factor number two will take over at that point and will allow tracts to share as a proportion of their relative value from that point forward.

And basically what we've got here, going through the same steps that we went through before, we use our hydrocarbon pore volume estimate of oil in place, which is 11,688,000 barrels of oil, and then we come down and list each tract across, the original oil in place from our hydrocarbon pore volume map for each tract, and the two proposed participation factors.

And if we go through the same procedure that we went through before, you can see that presently we have produced 1.3 million barrels of oil. It's slightly over 11 percent of the oil in place. And if we carry that on through, you can see we've got the same production credited to each tract. And like we saw before, tracts that are ahead in production are ahead of the field, and there are tracts that are behind.

But as we move on down, we see the significant differences on this exhibit, because in the future, when the reservoir recovery reaches 30 percent because of the tract one -- because of participation factor number one -- all of the tracts are equalized at 30-percent recovery, every tract has produced 30 percent of the oil in place on its tract, and the field, consequently, has produced 30 percent of the oil in the field.

From that point forward, we switch to participation factor number two, which is simply tract oil in place over unit oil in place, that ratio, and the tracts share equally from that point forward. And rather than the recovery equalizing at 100 percent, the recovery is equalized at 30 percent.

Q. Why is that important?

A. Well, that's the stated goal of the Applicant's proposal. This actually achieves that goal, and it does it in a reasonable time frame, in a reasonable manner.

Q. And the probability is that the secondary and primary production could achieve a 30-percent recovery? That's probable?

A. Oh, that's very probable. And it's quite likely, as we heard before, that it will achieve a higher recovery factor than 30 percent.

Q. All right, sir. Let's turn to the package of information that's contained in Exhibit 15. What have you compiled here, Mr. Payne?

A. This is an analysis of what has actually taken place on the Hamilton tract to date. Obviously, the tracts that have had more production relative to the other tracts are not going to share in as high a percentage of the future production until all the tracts are equalized, so what we're looking at is what has already taken place on the Hamilton tract, which is the tract that is the furthest ahead as a percentage of oil in place of any other tract.

So what we've plotted here is, oil production for the lease is the green solid curve. Gas production is the red solid curve. The green squares is the Amoco-posted west Texas intermediate price, which is my understanding of the contract basis for this production. And then the west Texas spot gas price are the red triangles down at the bottom of the curve.

Q. What's your conclusion?

A. Well, the conclusion is really based on the second page of this exhibit. If we turn to that, we've got another green solid curve on this tract, on this plot, which displays the percent recovery of the Hamilton tract versus time.

And the green solid line, if you look over on the left-hand Y axis, we're at 22 percent recovery of the oil in place. But if we look at the green squares where we've taken the oil production and multiplied it by the oil price and gas production and gas price, the total revenue to the Hamilton tract so far has been almost $13 million.

If the Hamilton tract had produced only as the field has produced, if its recovery to date was only 11 percent of the oil in place on that tract, multiplied by the oil and gas prices, its revenue would be something under $6 million. So there's a net difference of approximately $7 million that the Hamilton tract has enjoyed already. It's that far ahead of the field.

So even though they do not share to the factor -- to the percentage that some of the other tracts during the first phase of participation, they have already benefitted to the tune of over $7 million by being ahead of the other tracts.

Q. Have you made a calculation to describe to the Examiner how to establish a tract participation factor for phase one and for phase two, so that if he agrees with your opinions he could adopt an order that puts into practice or effect the equalization that you're trying to describe for us that would take place on Exhibit 14, I believe it is?

14 is your solution, I think, isn't it?

A. Yes, it is, and we have made those calculations, yes.

Q. All right, sir. Let me show you the calculations. We've marked it as Exhibit 16. All right, sir, describe for us what you would recommend the Examiner do.

A. Okay, basically the results and conclusions are the far right two columns of this exhibit.

To achieve equalization of tract recovery at 30 percent recovery -- the field will have produced 30 percent, and every tract will have been credited with 30 percent of its oil in place -- we would need to adopt the tract participation factors shown under phase one.

At 30 percent recovery of the oil in place, we would switch to the phase-two tract participation factor, and that would allow each tract to share proportional to its relative value to the unit from that point forward and would maintain that credibility until depletion of the reservoir.

Q. What do you recommend?

A. I recommend that we adopt phase-one and phase-two tract participation factors as are shown here on Exhibit 16.

Q. Let me show you what is the Applicant's -- see if

I can find it. It was Exhibit 9. I think maybe I've already given it to you.

A. Yes.

Q. Exhibit 9 is the pore volume map. Exhibit 4 is their structure map.

A. Yes.

Q. Okay? If you'll pull both of those out --

A. Okay.

Q. -- this overlay, Mr. Examiner, is going to be marked as Exhibit 18, and if you'll put the overlay on top of Exhibit Number --

A. -- 9.

Q. -- 9. You prepared the overlay?

A. Yes, I did.

Q. And what is the overlay of?

A. When I say I prepared it, it's --

Q. -- simply a duplication, isn't it?

A. It's a duplication of their Exhibit Number 9, that's correct.

And the first thing I'd like to do is just to lay it on top of Exhibit Number 9 to demonstrate that it is simply a duplication of that exhibit. We have not altered it in any way.

Q. When we look at your overlay on Exhibit 9 and look at the tract that contains the west half of Section

34, including the Snyder Tract 6, there's a portion of that section that is below the oil-water contact, as contoured on the Exhibit 9?

A. That's correct.

Q. And it's -- When you look at the well spots --

A. Yes.

Q. -- the well spots for each of the wells overlay on the overlay --

A. Yes.

Q. -- for well locations on Exhibit 9?

A. Yeah, everything lines up. The well locations, tract boundaries, unit boundary, everything lines up here.

Q. All right.

A. And although it's not labeled on this map, we heard testimony earlier today, and it's shown on the cross-sections, that the oil-water contact is minus 7617 and that it's uniform across the field.

Q. All right. Let's take the overlay now and put it on top of the structure map that the Applicant introduced, which I think is what? Exhibit 4, was it?

A. Yes.

Q. And when you correctly overlay our Exhibit 18 and line it up with the section lines to control it, what does it show you about the Applicant's oil-water contact?

A. Well, first of all you can clearly see that it's not uniform, and we heard testimony earlier today that it should be uniform if it's going to accurately reflect the hydrocarbon pore volume.

What we see, however, is that it varies from a high of minus 7600 on the State S tract to a low of minus 7630, approximately, on the Klein B tract. So it varies by 30 feet, according to this structure map.

The other thing that jumps out at you is that although we heard the Hamilton Number 1 was in a different location than is actually reported on the C-105, you see that there are some significant differences on the spotting of the well locations.

This is a one-inch-to-1000 map, and some of these are off by a couple hundred feet.

Q. All right. When we look at an oil-water contact, all you need to do is find that oil-water contact in one well, isn't it?

A. That's true. That -- That is true.

Q. And on the Klein Number 1, we've got the oil-water contact -- I think it's the Klein 1.

MR. BRUCE: Wiley 1.

Q. (By Mr. Kellahin) I'm sorry, it's the Wiley 1.

On the Wiley 1 we have got agreement with all the experts that that oil-water contact is at minus 7617?

A. That is how we interpret it. We've heard testimony this morning that that's how they interpret it, and that's how it's shown on their cross-sections.

Q. So all you ought to be able to do is take a structure map, find 7617, and follow the contour of the structure map, and then know where the oil-water contact is?

A. That's correct.

Q. And it should be in conformance to that line on the structure map?

A. That's true.

Q. But as we move into the Klein spacing unit, for which the Klein well was dedicated, it has a lower oil-water contact than indicated as 7617?

A. That's correct.

Q. All right. So the oil-water contact decreases on the Gillespie spacing unit for the Klein --

MR. BRUCE: It goes downstructure.

Q. (By Mr. Kellahin) It goes downstructure?

A. The oil-water contact is deeper -- according to this map, it's -- or it's shown deeper on this map on the Klein tract than it is on the Snyder tract.

Q. All right. When we move over to the Snyder tract, the oil-water contact is moving above minus 7617?

A. That's correct.

Q. Is that going to happen?

A. No, we don't even see an oil-water contact on the Klein tract, and nowhere in the field do we see an oil-water contact at minus 7600 as it's displayed on the State S.

No, that -- In my opinion, that's not an accurate representation of this field.

Q. If we use the Applicant's hydrocarbon pore volume map and apply the distribution of the reservoir based upon that map, then hydrocarbon pore volume is taken from the Snyder tract, based upon the mislocation of the oil-water contact?

A. That's correct, and it's inversely added to the Klein B tract.

Q. You've had an opportunity to hear the case today, Mr. Payne, you have looked in detail at all of these displays, you've visited with the Applicant.

Give us your engineering conclusions with regards to how we should resolve this matter.

A. I think we should adopt the participation factors that we show on Exhibit 16 in combination with the hydrocarbon pore volume map that was presented by Mr. Clemenson.

In short, our participation formula is not that much different than the Applicant's. We both have the same goal, to equalize recovery for these tracts at some point.

However, the Applicant's formula will not achieve its stated goal of equalizing recovery until we get to 100 percent recovery of oil in the field, and that's not going to happen.

Our formula simply brings that equalization point up to sometime that can truly occur in the life of this field.

Q. When you look at the Applicant's pore volume map, Exhibit 9, what is your degree of confidence that at least as to the well locations the Applicant has provided the appropriate pore volume value for each of the spots located on the exhibit?

A. The well spots are not consistent from the hydrocarbon pore volume map to the structure map, so therefore they can't be considered too reliable.

The oil-water contact does not conform to the structure map, so I cannot consider it to be reliable.

For that and the reasons we talked about, about the log analysis, I have more comfort and feel more positive about Mr. Clemenson's hydrocarbon pore volume map than Gillespie Exhibit Number 9.

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

We move the introduction of Exhibits 8 through 18.

EXAMINER CATANACH: Exhibits 8 through 18 will be admitted as evidence.

Let's take about a ten-minute break here before we start.

(Thereupon, a recess was taken at 3:25 p.m.)

(The following proceedings had at 3:43 p.m.)

EXAMINER CATANACH: Are you ready, Mr. Bruce?

MR. BRUCE: Yeah, I'm not sure how much I have here.

CROSS-EXAMINATION

BY MR. BRUCE:

Q. I think it's your Exhibit 9, Mr. Payne --

A. Yes.

Q. -- you were making corrections on porosity; is that correct?

A. No.

Q. You were talking about how you made various corrections to factors used by Mr. Nelson, and you talked about the Tornado charts?

A. Yes.

Q. Okay. Did you use the same Tornado chart to correct for every well?

A. No.

Q. What did you use?

A. It's inherent in the HDS program, but it's dependent upon the logging tool, the logging company.

Q. Okay. Did you attempt to correct your --

A. You're talking about resistivity, right?

Q. Excuse me. When you were doing your analysis on the various wells, did you attempt to correct your ϕ values to the core data?

A. Yes.

Q. And using that same Exhibit 9, I think right after the first blue page, now, what -- turning to the very first page, what do the various colors represent again, starting with the gray?

A. Okay, to make sure we're looking at the same page, I'm looking at the Earnestine State Number 1.

Q. Yes.

A. Okay. Moving from left to right, the first column is the gamma-ray, the raw gamma-ray reading.

The brown merely signifies reservoir.

The gray is shale, essentially, perforated interval.

The red bar in the depth bar in the depth column are the intervals that meet the net-pay criteria.

Moving across to the water saturation, we go left to right, from zero to 100 percent, and the blue shading is representative of water saturation, calculated water saturation.

The green shading is one minus that, or the hydrocarbon saturation. And where it's shaded green those are the intervals that meet that pay criteria.

Moving on across the page -- And I may have neglected to mention, on water saturation cutoff number it's 45 percent. So any water saturation less than 45 percent is shaded in green there, because actually hydrocarbon saturation is what we're showing, but it's less than 45-percent water saturation.

Moving on across, we show the neutron density curve, and it's calculated neutron density.

And then the red are the intervals that meet the net pay criteria of greater than 3-percent porosity, which is I think the same cutoff that Gillespie is using.

Q. Turning to the first page of that Exhibit, looking down at the Snyder 1 and 2 wells, your calculated hydrocarbon pore volumes for the Snyder 1 and Snyder 2 come out to what? 3.6?

A. No.

Q. Is that correct?

A. Are you summing them?

Q. Yeah, I'm just adding them.

A. Oh. Yeah.

Q. And what is that as a percentage of the total hydrocarbon pore volume?

A. I don't have that. Are you asking me to calculate that?

Q. Yeah, why don't you?

A. Okay. It's 11 percent of the total.

Q. Okay. Now, if you move over to the Gillespie calculated number -- what -- I think that totals up to 3.9. What is that as a percent of the total?

A. That's 10.6 percent of the total.

Q. How much?

A. 10.6.

Q. Okay. So there's -- As far as calculated amounts, it's pretty similar for those two wells?

A. But percentagewise, that's a big difference.

And really, that's a meaningless calculation. I mean, that -- those well locations -- This doesn't reflect well locations. You know, that doesn't mean anything.

Q. Did -- Turning back to --

A. Pure mathematic exercise.

Q. -- page -- the first page, the same one you discussed for me --

A. Okay.

Q. Did you calculate the hot streak as pay?

A. The hot streak as pay. What are you --

Q. Looking at the little -- Over on the left, the gray, where you see the spike that cuts the brown part in half.

A. It looks like that would meet the net pay criteria.

Q. Okay. So you did include that?

A. Yes. There were -- Yes. It looks like there's a foot and a half there or so.

Q. Going to your Exhibit 11, now, do all of your exhibits incorporate the well data from the two new wells? Snyder S Number 2 and the Klein Number 1?

A. I think where it's relevant, yes, they do.

The production data, all I could get from public record was through March, so -- If you want to go through them, Exhibit 8 does not include that. Exhibit 9 does. 10, it doesn't apply. 11 includes it. I think all the others do.

Q. Now, on your Exhibit 11, what was the formula you used to calculate the original oil in place?

A. The original oil in place, the boxed number?

Q. Yes, the boxed number.

A. The 11,655? That's the pore volume times one minus the water saturation, times B_o. I'm sorry, divided by, of course.

Q. Divided by B_o?

A. Yes.

Q. So pore volume times one minus the water saturation, divided by B_o?

A. Right. Again, the pore volume is in reservoir barrels. Multiply that by oil saturation, which is one minus S_w, divide by B_o to correct from reservoir barrels to stock tank barrels. So that's how that was done.

Q. Is this then -- Exhibit 11, is that a volumetric or a material balance calculation?

A. It is a material balance calculation.

What we do is alter the pore volume until we zero out the difference between pore volume and the reservoir fluids converted to reservoir barrels. When that difference is zero, we have defined the pore volume correctly, and we have balanced the reservoir.

There's no water influx here, no gas cap initially. So it -- what it essentially is, is a simplified material balance. It's a solution to some of the straight-line techniques that we can do on a spreadsheet, rather than graphically doing the same type of analysis.

But by zeroing out the last two columns, that's essentially what we've done, is fit a straight line to the graphical classic solutions of the material balance.

Q. Now, in using the material balance, that's only useful for the entire pool; is that correct? To determine what's in the entire pool?

A. No, in this reservoir, because we have no pressure gradients, it would also be useful on individual tracts as well.

Q. Have you or are you able to calculate future primary production as opposed to future secondary production?

A. That's two questions. Which one do you want?

Q. Well, can you calculate --

A. I am able to do it; I have not done it.

Q. You have not?

A. No.

Q. Neither one, you have not calculated what will be recovered under pressure maintenance conditions?

A. I guess that's four questions. I am able to do both of those; I have not done either one of them.

Q. Okay. In your opinion, might recovery in this pool exceed 30 percent under pressure-maintenance conditions?

A. In my opinion, it might.

Q. Is it a possibility or a probability?

A. I haven't attempted to quantify it.

Q. On your Exhibit 15 -- I'm not sure what the exhibit shows, other than that the Hamilton Federal lease was drilled first and produced first, as opposed to, say, the Snyder Ranch lease; is that correct?

A. The exhibit doesn't show that.

Q. What does it show?

A. The exhibit shows that the Hamilton Federal lease, since it has produced more of its oil in place as a percentage of the tract oil in place, relative to the field, that it has enjoyed a $7 million bonus over the recovery of the field to date. That money is in the bank, it's earning interest.

Whereas the other participants in the field who were going to make up for their participation with either of these proposed formulas to some degree -- yours, to a greater degree, ours -- that money is discounted money, it's future money. These guys, they've got their $7 million extra already.

Q. There's never any guarantee that your lease, if you had one next to my lease, if I had one, was going to get drilled first, is there?

A. No, there's no guarantee to that, no.

Q. Of course. And we're looking at the oil prices here, and during the Hamilton Federal lease production period at points the oil price dropped down to 14 barrels [*sic*].

Now, there's a chance the oil price could be higher in the future, and if you take that into account, maybe the Hamilton lease shouldn't have produced, because the Snyder Ranches lease will be selling oil at $25 a barrel or $20 a barrel. It looks like the average price here was something more like 17 barrels -- dollars a barrel.

A. Is there a question in there?

Q. Well, I mean, there's no guarantees, are there, that you're going to have a higher price, a lower price, produce your oil first, produce your oil last?

A. First of all, we actually see the highest oil price at the beginning of the Hamilton tract recovery, and some of the lower prices.

But again we can't speculate on what the price is going to be in the future. It may be much lower. But this money has been received, it's in the bank.

Plus the time value of that money. What we receive in the future, even if it is a higher price, by the time it's discounted back it may not be worth as much.

But that's all speculation. We can argue about that. That's speculation. These are facts, this is what's happened on this lease.

Q. Well, if that's the case, why don't you propose a retroactive judgment on income from the various tracts?

A. Would you accept that?

Q. Would anyone?

A. No, this is an equitable -- In all seriousness, this is an equitable, fair way to equalize recovery from these tracts into the future.

We probably can't make up for what's happened in the past, but we can do our best to equalize what could happen in the future.

Correlative rights have not been protected to this point, but this formula will go a long way to correcting that.

Q. That's the first I've heard of correlative rights.

A. Is that a question?

Q. Has anyone else agreed to your proposed participation formula, other than Snyder Ranches?

A. It hasn't been presented to anyone else.

Q. It has not?

A. It has not.

Q. So you don't know if anyone would agree to it anyway?

A. I'm sure that a lot of these tracts would agree to it.

MR. BRUCE: I have nothing further, Mr. Examiner.

MR. CREMER: I have some questions.

EXAMINATION

BY MR. CREMER:

Q. Mr. Payne, are you aware of any correlative rights between tracts that compete on a competitive -- or that produce on a competitive basis with each other in compliance with the rules and regulations of the OCD?

MR. KELLAHIN: Objection, irrelevant.

MR. CREMER: He brought up correlative rights, Mr. Examiner. I'm trying to show that this recovery factor that they've got in here is going to penalize the producing tract based on past production.

MR. KELLAHIN: No, sir, what we're talking about is correlative rights in the unit concept. Question to the witness was leasehold competitive correlative rights. It's and oranges. It's not a relevant question, Mr. Examiner.

MR. CREMER: But Mr. Bruce's question to the witness regarded previous production prior to the point of unitization, and the response had to do with correlative rights, the protection of correlative rights in that instance.

EXAMINER CATANACH: I think I'd agree with Mr. Kellahin on this issue. We're talking about correlative rights in the future for unit operations, so let's try and stick to that.

Q. (By Mr. Cremer) Well, okay, then, let's talk about the 30-percent recovery factor you put in your formula, phase one of your formula.

If I understand it right, we're talking about oil in place prior to any production from any wells from the wells which would be included in this unit; is that right?

A. Original oil in place?

Q. Right.

A. That's correct.

Q. Okay. And at the time 30 percent of the estimated oil in place has been produced, each tract in the unit will have produced or will have been allocated 30 percent of the oil in place for that tract, the estimated oil in place for that tract?

A. Under this formula, that's correct.

Q. So doesn't that penalize tracts which have already produced in the past?

A. Like the Hamilton tract?

Q. All of the tracts. Any tract that has produced in the past is penalized in relation to tracts which have not produced yet at all?

A. I don't know what your definition of "penalized" is, but the Hamilton tract, like we've shown, has already made more than $7 million than it would have if it had --

Q. Right, but my question is, why is that relevant -- I'm sorry, go ahead and finish your answer.

A. It's already benefitted to an additional $7 million, so there is no penalty involved. It's going to get lesser under our formula than under Gillespie's, but I don't see a penalty.

Q. Okay, my question is --

A. They've already gotten their share.

Q. Okay, then why is the $7 million relevant at all? Why is past production relevant, and where has it been stated that the goal is to have each tract in the unit have produced 30 percent at some -- I mean, have produced its proportionate share when 30 percent of the production has been achieved?

A. It was stated by Mr. Crow about nine o'clock this morning that that was the goal of the formula. And he also stated that the only time it would get there was at a hundred percent.

Q. I have to -- Well, I believe the testimony is more in the nature of --

MR. KELLAHIN: Counsel is arguing with the witness, and he's making a closing statement. If you keep to a question we'd get through this.

Q. (By Mr. Cremer) The recovery factor that you've put into this formula is such that tracts that have produced prior to unitization will receive a lower percentage of unit production so that tracts which have not produced yet can, in effect, catch up by the time 30 percent of the estimated oil is in place produced from the unit; is that correct?

A. You are correct. And the only difference between our participation formula proposal and the Applicant's proposal is that ours reaches the stated goal of both proposals.

Their proposal is to do the same thing, but it's at 100-percent recovery. We're not going to get to that. It's quite likely that we'll get to 30 percent.

So if we both have the same goal, let's reach it at a reasonable point in time. 100-percent recovery is not going to happen. That is the only difference in the two proposals.

Q. You think 30 percent is a reasonable -- Where did you pick the 30 percent?

A. I had --

Q. Obviously, you had picked it before --

A. I had picked --

Q. -- you heard any testimony this morning.

A. I had picked it before because I think it is a reasonable number.

But from what I've heard this morning, which is different than what we heard last January, 30 percent is all we're going to get. So it can't be any higher, but it could be lower.

MR. CREMER: I have no further questions.

EXAMINER CATANACH: Do you --

MR. KELLAHIN: No, sir, I'm done.

EXAMINER CATANACH: Just a couple, Mr. Payne.

EXAMINATION

BY EXAMINER CATANACH:

Q. Did you do the individual log analysis and determine the same -- did you use the same method in determining pore volumes that was done by Gillespie, in that -- did you use every -- did you look at every log and determine -- and calculate it every half foot?

A. Yes, sir, we looked at every -- we digitized the same curves that they digitized, with the exception, I believe, of the Hamilton 3, at half-foot intervals, and then made the same type of calculation that they made, with the differences we talked about in R_t. We used a corrected R_t, they did not. And we used both the neutron and the density curve, whereas they used only density.

But the water saturation formula was the same, hydrocarbon pore volume saturation was the same, and they were both done on half-foot intervals.

Q. Did you examine any of the other data generated by the Applicant to see if any of the other wells beside the Hamilton Number 3 had some incorrect data associated with them?

A. I looked at every well. When you digitize curves, there are going to be some very subtle differences in the numbers, but that was the most glaring exception, or difference, that I saw.

EXAMINER CATANACH: I don't have anything further of this witness.

MR. KELLAHIN: That concludes our direct case, Mr. Examiner.

MR. BRUCE: Mr. Examiner, I think there may be one or two rebuttal witnesses, but -- Phillips has one and we may have one.

MR. CREMER: Call Mr. Birkelo to the stand.

BRAD BIRKELO,

the witness herein, after having been first duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. CREMER:

Q. For the record, please state your name and city of residence.

A. My name is Brad Birkelo, and I live in Midland, Texas.

Q. What is your occupation and who is your employer?

A. I'm employed by Phillips petroleum as a geophysicist.

Q. Have you previously testified before the OCD as a geophysicist?

A. No, I have not.

Q. Please tell us your educational and professional qualifications.

A. I have a bachelor's degree in geology from the University of Minnesota in 1982, I have a bachelor's degree in geophysics from the University of Minnesota in 1983, and I have a master's degree in geophysics from the University of Kansas in 1987.

Professional experience, I have worked for over six years with Phillips, primarily in areas of 3-D seismic interpretation, processing and acquisition planning. My experience includes approximately a dozen to a dozen and a half 3-D surveys, primarily in west Texas.

MR. CREMER: Okay. At this time, I would move the admission of Mr. Birkelo as an expert witness in geological and geophysical matters in this case.

EXAMINER CATANACH: Mr. Birkelo is so qualified.

Were you sworn in, Mr. Birkelo?

THE WITNESS: Yes, I was.

Q. (By Mr. Cremer) Are you familiar with the geologic and geophysical mapping of the proposed unit area where the West Lovington-Strawn --

A. Yes, I am.

Q. -- unit -- Okay.

As you know -- Well, you're also familiar with the identification of the tracts in the unit?

A. Yes, I am.
Q. Tract 6, I believe, being the tract that's owned by Snyder Ranches, Inc.?
A. Yes.
Q. Okay. Based on your knowledge of the reservoir of hydrocarbons underlying the proposed unit area, what's your opinion of the quality of the reservoir underlying tract 6 of the unit?
A. Tract 6 in general has a lesser amount of porosity, both in terms of porosity -- or in terms of thickness and also in terms of absolute value of porosity.
In other words, the average porosity value in the zones that contain porosity on that tract tend to be lower than, say, the Speight tract, the Earnestine tract and the Hamilton tract.
Q. Okay. You're also familiar with mapping --
A. Yes, I am.
Q. -- that was done and the history of the mapping from November, December of last year, on through the current maps that have been presented by Gillespie?
A. Yes, I am.
Q. Okay. When were you first given the opportunity to examine the data and do your own mapping?
A. I believe that it was the end of December where I took a trip to Dalen's office in Dallas and at that time

was given an opportunity to view the seismic data on their work station, interpreted the data for two days, and when I -- at the point in time I left, I was comfortable that I had a reasonable understanding of what was going on geologically within the reservoir.

Q. Okay. And then you came back and conducted your own mapping -- produced your own maps, in other words, of the --

A. Yes, my primary role was to kind of judge the mapping that was done by the operator, in this case Gillespie, in conjunction with their partner, Dalen, and my purpose was to make sure that what they were doing was fair and reasonable and primarily protected the interest of Phillips Petroleum and its royalty owners within this particular unit.

Q. At the time you went examine the seismic material in Dalen's offices, did Phillips already have a stated position either in opposition to or in support of the proposed unit?

A. No, as a matter of fact, the reason we went there was primarily to develop an opinion based on all of the data -- you know, all of the data that was available. We didn't feel that we could adequately judge the initial unitization proposal that was given back in November, based on the information that we had. We felt that the integration of the seismic data was critical to judging whether that proposal was fair or not.

And so we took a trip to Dallas in order to view that data and to try to develop a feel for whether or not their mapping was appropriate.

Q. And were the final maps that -- Well, first let me ask you this. Did your mapping generally correspond with Dalen and Gillespie's mapping of the unit area?

A. Yeah, actually it was -- I was surprised that it corresponded as closely as it did. We had very good agreement over most of the places.

There were a couple placed where we differed, and it was not -- it was in the areas, I think, the areas -- you know, primarily in the areas where we've seen discussion here today.

Q. Specifically with regard to the hydrocarbon pore volume numbers that you developed based on the information that you had, were those numbers basically in conformance with Gillespie and Dalen's mapping?

A. My actual mapping, what I did is, I didn't actually run through log analysis myself. I didn't feel that I was qualified as a geophysicist to come up with those numbers.

What I did is a rough calculation on the paper logs to convince myself that the numbers that they had come up with were reasonable. After I convinced myself those numbers were reasonable, I used their numbers that they developed from their log analysis for my hydrocarbon pore mapping.

Q. Okay. Now, was the actual final mapping -- The maps in their current state, were those prepared before or after the last two wells in the proposed unit area were drilled?

A. The discussions that we had with Gillespie and Dalen, after my visit to view the seismic data and after I had a chance to come back and integrate it with the geologic data that we had, at that point in time we had some -- what I felt were some areas where the -- their mapping was maybe not taking into account certain things which I had seen on the seismic data.

At that point in time, I was informed that there were going to be two additional wells drilled in the unit or -- you know, within the unit, proposed unit area. And the agreement was made at that point in time that we would revisit the final mapping again after the data from those two had been integrated, or been collected, so we could basically deal with the mapping one last time after all of the available data was there.

Q. And did the data received in the drilling of the two additional wells change the mapping in any way, in your opinion?

A. It changed it subtly but not in a gross, overall sense. It helped define, I believe, the northern extent a little bit better and also the southeastern extent. It showed that the original mapping was probably a little too optimistic down there.

Q. Okay. So testimony we heard this morning -- I believe it was on the cross-examination of Mr. Crow -- Mr. Kellahin mentioned that the isopach and structure maps didn't change much, but the pore volume maps did change.

A. Yes.

Q. Explain the reason why -- Well, first of all, is that a reasonable possibility that that could happen?

A. Yeah, actually it's a reasonable possibility.

If you look at what the isopach map is actually showing, it's showing a total thickness of porosity that's above 3 percent. It doesn't make any value judgments as to whether that porosity is 4 percent, 8 percent, 10 percent, 12 percent.

It's going to treat 80 feet of 3-percent porosity exactly the same as it treats 80 feet of 8-percent porosity.

Yet the case of where you've got 80 feet of 8-percent porosity is going to contain twice as much oil of the original oil in place as the case where you've got 4 percent.

And I think that was -- I think that's a point that needs to be brought up.

Q. So then in summary, I guess, what happened was, whereas the thickness of the reservoir under the Hamilton tract, for instance, didn't change, the information that you had indicated that that portion of the reservoir was much more porous than originally thought?

A. Yes, that's exactly right.

Q. Okay. Mr. Clemenson, I believe, testified that based on the information contained in this BTA Townsend well and the Chambers Number 1 well, which are approximately five miles apart -- That was what he basically used to develop his zero line and his oil-water contact line in his mapping; is that --

A. That's what I understood, that he integrated the data from approximately a five-mile area along that northern edge of the unit.

Q. And in your opinion, is it possible for the geology and the structure to differ significantly within a five-mile area?

A. Sure, if you've got two points that are five miles apart or three miles apart, you've got no choice, really, but to draw a straight line between there, unless you've got some other data that you can bring into play.

And that's essentially, I think, what's happened with the zero line of the pore volume map on the final map that Gillespie has done. From when I looked at the data, there were indications to me that the Strawn at that particular area, based on the seismic data, dipped below the oil-water contact.

And so even though you can have porous reef in that section, in that northwest quarter of Section 34, almost all of that porosity was actually below the oil-water contact.

Q. So what you're saying is that the seismic information you had available to you actually helped you in making that determination, as opposed to if you just had well-log data to rely on that information?

A. If I had well-log data alone, it would have been difficult to justify that re-entrant.

But the seismic data, in my mind, very clearly showed that there, and it was very justified in being in the final map.

Q. Okay. Earlier, Mr. Scolman was questioned extensively on the method by which his pore volume map was developed.

You've had a chance to review it, you know what went into it, you've done your own mapping.

In your opinion, was the method that he utilized in developing that map accurate?

A. Yes, I agree that the method he used was technically very sound and, in my opinion, resulted in the best possible quality product.

Q. Okay. You've also had the opportunity to review the maps prepared by the witnesses for Snyder Ranches, Inc., in this case.

What is your opinion as to the quality of those -- or the accurateness, let's say, of those maps?

A. Their maps appear to honor their well-control data or the points that they've posted on there. And from that point of view, I don't have -- I really can't quarrel with their contouring.

The problem that I have with their maps is that there is additional information available that was not taken into account.

The additional information suggests that some of their mapping is inaccurate. And that is, I guess, the biggest bone of contention in my mind between their maps and the maps that were presented by Gillespie.

Q. Speaking of additional information, to your knowledge, was information from the wells outside the unit that were relied upon by the witnesses for Snyder Ranches, Inc., also relied upon by Gillespie and Dalen in their preparation of maps?

A. I've had conversations with them on a number of occasions that suggested that they used data over a very large area.

However, for the purposes of the unitization proposal, they stuck just to the -- You know, they actually presented data just within the unit area, even though it actually represents an integration of a much larger area.

Q. You were present and involved in a number of negotiations -- or most of the negotiations between Dalen, Gillespie, Phillips, in coming to a consensus on the way this unit was eventually proposed; is that right?

A. I was involved, certainly, in some of them.

Q. To your knowledge, was there any communication given to you, ever, by anyone, either verbally or impliedly, that if the pore volume numbers were increased in the tract in which you own an interest, you would then -- or Phillips would then acquiesce to the formation of the unit without objection?

A. No, that's not correct.

Our goal was to achieve -- And this was our stated goal from the beginning and it still continues to be the goal of Phillips Petroleum, is to come up with the most accurate representation of the reservoir geometry and extent, so it best treats fairly all of the owners, you know, certainly within the unit area.

We really strived and made a very serious attempt to come up with the answer that was best supported by the data that we had available to us.

Q. And based upon your knowledge of the production allocation formula that's been proposed by Gillespie, has it ever been the intent of the working interest owners in the unit to equalize recovery of hydrocarbons, taking into consideration prior production from the tracts included in the unit?

A. No, that's not my understanding.

In fact, Phillips Petroleum in general feels it's a bad idea to take into account past production, you know, in the formation of these types of units. There's too many unknowns that come into play.

However, in the interest of expediting the formation of this unit, we have agreed to the adjustment of the unit participation formulas in order to reflect some degree of the past production.

Q. Okay. And to your knowledge, is it common to come up with a recovery formula which does penalize tracts for past production?

A. Not to my knowledge. But in truthfulness, my knowledge is somewhat limited on that sort of thing. It's not something I've been involved with a lot.

Q. When you were in Dallas examining the seismic and other geophysical data that was provided to you there, what was your opinion as to the quality of it? Was it reliable?

A. The quality of the seismic data looked excellent to me.

It was very easy to map the top of the Strawn, it was very easy to see indications within the unit area of porosity development and where porosity development was better, where it was not so good.

It was even possible, in my opinion, to make some sort of qualitative statements as to where the porosity was developing within the Strawn interval to some extent.

Q. So you felt very comfortable interpreting it and relying upon it in your mapping?

A. Yeah, I had no problem at all with that.

MR. CREMER: Okay. I have no further questions, Mr. Examiner.

EXAMINER CATANACH: Mr. Kellahin?

EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Birkelo, let's see your maps.

A. I don't have maps here to present today.

Q. What kind of maps do you have that you didn't present?

A. The maps -- the types of mapping I did were very similar to the mapping that Mr. Scolman did prior to his coming up with the final pore volume map.

Q. You didn't think to bring those with you today?

A. I didn't think that that was the issue at hand here, truthfully.

Q. The oil-water contact, is that something you as a geophysicist can see on 3-D seismic data?

A. No, not on the 3-D seismic data.

Q. All right. So you and Mr. Scolman agree that you can't use 3-D seismic data to pick an oil-water contact?

A. That is correct, in this particular case it's not appropriate to actually measure it directly on the seismic data.

Q. All right. I'm confused about your involvement in this process. Help me remember what you've just said.

At the end of December, are you looking at the Dalen-Gillespie maps?

A. At the end of December I have seen a copy from the working interest owners' meeting of the original maps.

Q. The hydrocarbon pore volume map --

A. The hydrocarbon pore volume map.

Q. -- that we've got in the record?

A. That's correct.

Q. All right. Had you looked at 3-D seismic data at that point?

A. At the working interest owners' meeting, I had not looked at the 3-D seismic data.

Q. At what point did you agree with the Gillespie-Dalen map?

A. The Gillespie-Dalen map -- Essentially, we reached a consensus following the drilling of the final two wells, the Klein Number 1 and the Snyder Number 2 wells.

We agreed at the point in time at which we conversed, following my look at their seismic data, that we would postpone any remapping of the data until after we had collected the data from those two wells and recalibrated our maps based on those two wells.

Q. Bear with me. You're confusing me. After the December working interest owner meeting, you've got at least the hydrocarbon pore volume map?

A. The working interest owners' meeting was actually in November.

I have in my hands at that point the original hydrocarbon pore volume map that I've seen in evidence here today, I believe, from the Snyder Ranch companies.

Q. All right. When did you go to Dallas to look at the seismic data?

A. It was the end of December.

Q. So you've seen the 3-D seismic work at the end of December?

A. That's -- Yes, I was allowed to work it myself, independently.

Q. All right. Did you see the seismic data before or after you had seen the hydrocarbon pore volume map?

A. I saw the seismic data after I saw their original hydrocarbon pore volume map.

Q. And after you saw the seismic data, then I thought you told us that you were in substantial agreement with their hydrocarbon pore volume map, with some changes.

A. I saw some areas where I felt that they had not perhaps taken into account as much information as was actually in the seismic data, and that was pointed out to them at that time.

Q. And you're specifically looking at the pore volume in the Hamilton tract?

A. No, actually not at all. We're specifically looking at the entire unit. It was not limited strictly to the Hamilton tract.

Q. And based upon pointing that out to them, did they change any of their maps in January of 1995?

A. Not that I'm aware of. I -- we didn't -- You know, we did not agree on the final map until after the final two wells were drilled.

Q. In December you've seen the data on Mr. Scolman's computer?

A. That's correct.

Q. Does he give you a copy of any of the data?

A. I don't end up with -- What I've got are essentially hard-copy plots of some of the things that -- you know, a couple of -- you know, 2-D profiles across the line. Nothing -- No hard data, nothing I can take back, model or anything else.

Q. What did you take when you left his office?

A. I took a diskette with some color graphics, files essentially that show 2-D lines, 2-D profiles that cross the 3-D data.

The intent there was to illustrate to our management the rationale behind the hydrocarbon pore volume mapping that was done --

Q. I'm not interested in the intent. I want to know what you took with you.

A. I took with me cross-sections, four profiles across the seismic -- across the 3-D volume.

In addition to that, I took maps essentially of a couple of seismic attributes that corresponded to the topper, basically the top of the Strawn interval, so I could do my own depth conversation back in the office.

Q. Did Mr. Scolman provide you with a velocity map?

A. He did not.

Q. Did you get any other kind of mapping interpretations from him at that point?

A. I got no interpretation whatsoever. The idea was that I would go and make my own independent judgment on what I saw in the data.

Q. Did you take with you enough data by which you could produce your own velocity map?

A. Yes, I did. At least in the area within the unit -- you know, the unitized boundary, which was the limit of the data that I was shown.

Q. Did you get a shot-point map to demonstrate exactly where the configuration was to set up the 3-D work?

A. The data that I took with me had XY locations essentially coded into the values themselves.

Q. Did you have enough information that you could prepare your own maps?

A. Over a very small area, yes, I could. Over the specific unit area, yeah.

Q. And did those maps agree with Mr. Scolman's maps?

A. They agreed in -- They were pretty close, yes.

Q. Did you show him your work product?

A. We talked about and exchanged -- in terms of the final consensus that we reached as far as our -- the maps that have been presented here today, yes, we did.

Q. And when did that take place?

A. That took place with -- I don't have exact dates, but it took place primarily in April of this year.

Q. When you and Mr. Scolman were trying to resolve the differences between you, what kind of differences were you resolving?

A. We were resolving what -- Basically, we were looking at the seismic attributes and giving -- essentially giving each other what we felt were our interpretations of what those attributes actually meant.

Q. Like what?

A. For example, amplitude maps on the top of the Strawn. By looking at the amplitude, you can make adjustments as far as the porosity development near the top of the reef. Those are the types of things.

Those maps were prepared, actually, in Dalen's office when I was there in December. And those are the types of things that we discussed concerning the -- you know, the changes that I felt ought to be made to the maps.

Q. When you're making changes to the map, what specifically are you changing in relation to the hydrocarbon pore volume map?

A. The hydrocarbon pore volume map, per se, is not changed. What we're looking at is the structural configuration of the top of the Strawn and also a generalized distribution of the porosity within the unit area.

Q. Are you adding reservoir volume under the seismic analysis?

A. I'm not sure I understand what you mean by "adding reservoir volume".

Q. Well, we talked earlier with Mr. Scolman about trying to find the edge of the reservoir, and I would think that you would be looking for some porosity indication so that you would know you were at the edge of the reservoir.

A. That was --

Q. Is that how you do that?

A. That was part of the -- You know, where to draw the zero line, where the top of the Strawn dips below the oil-water contact, those are the sorts of issues that we discussed.

Q. All right. Rather than porosity value, are you simply looking for a reservoir indicator of some kind?

A. I'm not sure I understand the question.

Q. Is it an amplitude? Is that what this is?

A. The character of the seismic wavelength will change, depending upon the amount of porosity and the distribution of the porosity, and those are the types of things that we were discussing.

Q. All right. I'm looking for something -- As a layman I don't know your vocabulary, but I'm looking for a porosity indicator in some kind of reflection or amplitude that you see in all this stuff.

A. I'm not -- I'm having trouble following your question, but I think -- well --

Q. Porosity is a component of what you're looking for, isn't it?

A. We are looking for indications of porosity. We don't see porosity itself; we see indications of porosity.

Q. You don't have a direct measurement of porosity?

A. That -- The seismic attributes are reflected -- The seismic attributes that we measure reflect porosity and are related to porosity. But you do not -- By measuring specific seismic values, you do not actually get a porosity value.

Q. It's not like log analysis?

A. It's nothing like log analysis.

Q. All right, it's an empirical thing where you're looking at one thing and inferring or interpreting a porosity?

A. That's -- Generally it's done. There are modeling techniques and calibration techniques that can make it a lot less subjective or a lot -- well, I'm not sure I'm using the right -- that make it a lot less interpretive, if I'm making myself clear to you.

Q. You're going to have a measurement in terms of time, this millisecond thing --

A. Okay.

Q. -- where it is going to respond to whatever you're reading, which will give you an inference of a reservoir depth or dimension vertically, right?

A. I don't know if I'd choose to put it that way. It's the kind of --

Q. I'm a poor lawyer. You tell me.

A. No, I -- Actually I need to answer your -- I mean, I'd like to answer your question because I --

Q. Help me. Is that not what you're saying? You're seeing something that gives you the ability to infer a reservoir dimension, a depth, that may have some porosity component to it?

A. The distribution of porosity within the reservoir will cause different signatures within the interval that is represented on the seismic data of the reservoir.

And those wave-form characters, the amplitude and the character of those -- essentially the wiggly lines -- change depending upon how the porosity is distributed throughout the reef section and how thick that reef section is in general.

Q. All right. At this depth, with this kind of equipment and analysis, to what degree can we define a thickness? How accurate can we be?

A. The thicknesses for the most part are defined at the wellbores.

And so what we've done is, we've gone in and at each individual wellbore we've got a calibration of exactly how thick that is, and then we look for changes away from that.

It's not like we were coming up -- we have to come up with an absolute number. We've got 10 or 11, you know, calibration points within the unit area, and we look for changes away from those wellbores.

What we use the seismic to do is to fill in the gaps, and at 110-foot spacings that seismic data does a very good job of filling in the gaps between the wellbores. It doesn't make us just make things up in our heads. We can actually go in and use what the seismic data is telling us is there, or at least indicating that, to guide our mapping.

Q. If I've got this grid size, 110 foot on a side --

A. Uh-huh.

Q. -- and if I've got a 30-foot reservoir thickness at my wellbore that I've measured by log, I know that much porosity is there --

A. That's correct.

Q. -- and I'm using that 30-foot interval, what is the degree of accuracy as we move out from the wellbore, using your method? Plus or minus some percentage, I assume, is the degree of accuracy?

A. It involves -- actually, if you want to get that plus or minus, you need to do a -- It's a fairly detailed analysis of velocities, frequency of the seismic data and a lot of other things.

Q. All right. If you're right next to the wellbore, what's the degree of accuracy of this analysis you've applied to the reservoir?

A. At the wellbore, at that six-inch hole in the ground, theoretically you know exactly what's there.

Q. Plus or minus one percent?

A. It depends upon actually -- At that point it depends on the accuracy of your logs in representing what's actually happening in the ground there.

Q. All right. As we move out from the wellbore in any dimension, how much do we reduce the accuracy of the method?

A. That's not something you can answer straightforward. It really depends upon your degree of well control, the quality of the seismic data and the degree of variability that takes place not only within the reservoir but within the overburden.

Q. I assume you did all that in this reservoir, didn't you?

A. The analysis that was done by myself, which is really all I can speak for at this point, was a qualitative analysis to try to determine whether or not the hydrocarbon pore volume was being distributed fairly within the proposed unitized area. That is what I did.

I don't claim to have modeled it, I don't claim to have done the detailed calibration that Mr. Scolman did. His methods, as he described them, are the appropriate methods to use, and I take -- I have confidence that his analysis is reasonable.

Q. All right. You took his database of information, assumed it correct, believed it to be, and proceeded from there; is that how this happened?

A. No, I did not take his database.

I took information that I saw that agreed essentially with his interpretation of the reservoir, as they have it mapped and as they have presented, and have essentially found no major flaws with it.

Q. All right. You didn't make an independent judgment or study of the accuracy of the entire process that Mr. Scolman was relying upon for his conclusions?

A. That's correct.

MR. KELLAHIN: All right, sir. Thank you. That's all.

MR. CREMER: I don't have anything.

EXAMINER CATANACH: I have no questions of this witness. He may be excused.

Mr. Bruce?

MR. BRUCE: Very briefly, I'd like to recall Mr. Nelson.

<u>RALPH NELSON</u> (Recalled),

the witness herein, having been previously duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Mr. Nelson, I think you have in front of you Snyder Ranches Exhibit 10, and previously Mr. Kellahin had questioned you a little bit about the -- I think it's the Hamilton Federal Well Number 3.

A. Yes, he did.

Q. Could you describe what you did when you chose your -- or calculated the DPHI and how you went about it and why you think your numbers are accurate?

A. Well, once again, as I explained, we compared the core data to the density log data, the porosity log data, and found that the 85 percent of density porosity most accurately correlated between the log porosity and the core porosity. The logs are electrical, nuclear, acoustic measurements. We were relying on the rock data.

In this one particular case, this was a well that was drilled before my employment at Dalen Enserch, and I was not familiar with that history. It appears that we did use the wrong log to calculate that value.

But the difference between the two values, the one that we calculated and the one that Mr. Payne calculated, is 3.6 percent, as -- from his numbers.

Q. For that particular well?

A. For that particular well. We're talking a difference of 3.6 percent for that particular well.

Q. So if there was an error, it's just very minor?

A. It's very minor, yes, it is.

MR. BRUCE: That's all I have, Mr. Examiner.

EXAMINER CATANACH: Mr. Kellahin?

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Nelson, this comparison of core data to get the .85 -- Getting tired, I forgot the number. The adjustment -- The gas-effect number is .85.

There is a comparison made of core data?

A. That's correct.

Q. Is it reduced to a writing, a document, a spreadsheet, a table of some kind?

A. No, I do not have one prepared that way.

Q. Do you have one prepared at all?

A. What we have is, we compared foot by foot core analysis --

Q. Yes, sir.

A. -- to log.

Q. That comparison, did you reduce it to writing?

A. I have it in my notes somewhere, but I don't have it here.

Q. It's not in terms of something written that you have with you today?

A. That's correct.

MR. KELLAHIN: Okay. I'll talk to Mr. Bruce about that information.

Thank you. I have no further questions.

MR. BRUCE: Mr. Examiner, I omitted to ask Mr. Nelson one question in connection with his answer.

FURTHER EXAMINATION

BY MR. BRUCE:

Q. Why didn't you use the Tornado charts?

A. Well, there were five different logging companies, one of which, BPP, we don't know if they've ever printed a Tornado chart, and we doubted seriously that we could -- and would feel good about using one or assuming another company's Tornado chart to make these corrections.

Q. That was on the R_t, the resistivity?

A. That was on the R_t, the resistivity, that's correct.

MR. BRUCE: Finally, Mr. Examiner, I'm done.

EXAMINER CATANACH: The witness may be excused.

Would we like to give brief closing statements, or do we want to just waive them?

MR. KELLAHIN: Mr. Examiner, let me suggest that our time might be best served if you will let Mr. Bruce and I and whoever else would like to submit proposed orders for you to think about -- I have nothing else to add at this point.

There will be things that I would propose to put in the order that would explain our position and would substitute for a closing argument.

It's almost past my bedtime, Mr. Examiner. I believe I'm done. Thank you.

EXAMINER CATANACH: Mr. Bruce?

MR. BRUCE: I am much younger than Mr. Kellahin, and I don't have to go to bed for another two hours, but -- That's fine with me.

I think Tom and I know we can throw what we want to say into the proposed order and -- We'll even give it to you to on disc if you want.

EXAMINER CATANACH: Okay. To save a little work on the proposed orders, I suggest you just focus on the statutory unit.

MR. KELLAHIN: Yes, sir.

EXAMINER CATANACH: You don't have to worry about the pressure-maintenance project part of it. That might save a little effort.

Is there anything further in this case?

MR. KELLAHIN: No, sir.

EXAMINER CATANACH: There being nothing further, these cases, 11,194 and 11,195, will be taken under advisement.

This hearing is finally adjourned.

(Thereupon, these proceedings were concluded at 4:50 p.m.)

* * *

I do hereby certify that the foregoing is
a complete record of the proceedings in
the Examiner hearing of Case No. ______,
heard by me on ________________ 19_____.

__________________________, Examiner
Oil Conservation Division

CERTIFICATE OF REPORTER

STATE OF NEW MEXICO)
) ss.
COUNTY OF SANTA FE)

I, Steven T. Brenner, Certified Court Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation Division was reported by me; that I transcribed my notes; and that the foregoing is a true and accurate record of the proceedings.

I FURTHER CERTIFY that I am not a relative or employee of any of the parties or attorneys involved in this matter and that I have no personal interest in the final disposition of this matter.

WITNESS MY HAND AND SEAL June 26th, 1995.

Steven T. Brenner

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998