STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION COMMISSION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION COMMISSION FOR THE PURPOSE OF CONSIDERING:	)	
APPLICATION OF SAPIENT ENERGY CORPORATION FOR SPECIAL POOL RULES, LEA COUNTY, NEW MEXICO	)	CASE NO. 12,605
AMENDED APPLICATION OF SAPIENT ENERGY CORPORATION FOR AN UNORTHODOX WELL LOCATION AND TWO NONSTANDARD 160-ACRE SPACING UNITS, OR IN THE ALTERNATIVE ONE NONSTANDARD 160-ACRE SPACING AND PRORATION UNIT, LEA COUNTY, NEW MEXICO	)	CASE NO. 12,587
	)	(Consolidated)

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSION HEARING

ORIGINAL

BEFORE: LORI WROTENBERY, CHAIRMAN
JAMI BAILEY, COMMISSIONER
ROBERT LEE, COMMISSIONER

December 4th, 2001

Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Commission, LORI WROTENBERY, Chairman, on Tuesday, December 4th, 2001, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South Saint Francis Drive, Room 102, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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I N D E X

December 4th, 2001
Commission Hearing
CASE NOS. 12,605 and 12,587 (Consolidated)

(Continued...)

SAPIENT WITNESSES (Rebuttal):

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E X H I B I T S

Sapient	Identified	Admitted
Exhibit 1	24	52
Exhibit 2	-	52
Exhibit 3	-	52
Exhibit 4	-	52
Exhibit 5	-	52
Exhibit 6	-	52
Exhibit 7	-	52
Exhibit 8	-	52
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Exhibit 24-A	81	104
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Exhibit 25	104	104
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Exhibit 27	91	104
Exhibit 28	94	104
Exhibit 29	102	104
Exhibit 29-A	85	104
Exhibit 30	103	104
Exhibit 31-A	-	104

(Continued...)

E X H I B I T S (Continued)

Sapient	Identified	Admitted
Exhibit 31-B	-	104
Exhibit 31-C	-	104
Exhibit 31-D	-	104
Exhibit 31-E	-	104
Exhibit 31-F	-	104
Exhibit 31-G	39, 98	104
Exhibit 32	149	252
Exhibit 33	243	252
Exhibit 34	247	252

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Conoco/Chevron	Identified	Admitted
Exhibit 1	122	145
Exhibit 2	124	145
Exhibit 3	207	-
Exhibit 3 (Revised)	130	145
Exhibit 4	-	-
Exhibit 4 (Revised)	127	145
Exhibit 5	-	-
Exhibit 5 (Revised)	132	145
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Exhibit 9	193	199
Exhibit 10	196	199
Exhibit 11	136	145
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* * *

WHEREUPON, the following proceedings were had at 9:49 a.m.:

CHAIRMAN WROTENBERY: We've got two cases, then, we'll call now. Case 12,605, the Application of Sapient Energy Corporation for special pool rules in Lea County, New Mexico. This case is being heard on the Application of Sapient Energy Company, Chevron USA Production Company and Conoco, Inc.

And then also Case 12,587, the amended Application of Sapient Energy Corporation for an unorthodox well location and two nonstandard 160-acre spacing units, or in the alternative one nonstandard 160-acre spacing and proration unit, in Lea County, New Mexico, this case being heard again *de novo* upon the Application of Sapient Energy Corporation, Chevron USA Production Company and Conoco, Inc.

And we'll call for appearances.

MR. KELLAHIN: Members of the Commission, my name is Tom Kellahin. I'm with the Santa Fe law firm of Kellahin and Kellahin. I'm here today on behalf of the Applicant, Sapient Energy Corp. I have two witnesses to be sworn.

MR. CARR: May it please the Examiner, my name is William F. Carr with the Santa Fe office of the law firm Holland and Hart, L.L.P. We represent Chevron USA

Production Company and Conoco, Inc. in this matter. Appearing with me here today is Bruce A. Connell, Esquire, in-house counsel for Conoco, and we have two witnesses.

CHAIRMAN WROTENBERY: Thank you, Mr. Kellahin, Mr. Carr.

Any other appearances in this case? I don't see any.

Why don't we go ahead and ask the witnesses to stand and be sworn?

(Thereupon, the witnesses were sworn.)

CHAIRMAN WROTENBERY: Mr. Kellahin, Mr. Carr, you had given some time estimates for your cases today. Could you talk to me a little bit about how you would like to proceed and what period of time it will take? For instance, do you want to do opening statements?

MR. KELLAHIN: Madame Chairman, Mr. Carr and I have talked about this. Attorney Ross has communicated with us about a processing procedure. I believe we -- In compliance with his direction, we have submitted to you detailed prehearing statements, including a bunch of details about this pool.

In addition, he's afforded us an opportunity to make a brief opening statement, and that his proposal to his is at the conclusion of the evidentiary process we would be afforded ten days post-hearing to provide written

argument and submit to the Commission our proposed orders.

Mr. Carr and I have both streamlined our cases. At the Examiner hearing before Mr. Stogner back on March 1st, there were six witnesses. Conoco had an engineer and a geologist, Chevron had an engineer and a geologist, Sapient had an engineer and geologist and a landperson.

We have attempted to focus on what we think are the technical issues, because this is a technical case. I think we can conclude by the end of the day, but I am not good at guessing how long these witnesses will testify nor how detailed you want their testimony to be.

CHAIRMAN WROTENBERY: Mr. Carr, are you agreeing?

MR. CARR: I concur in the statement of Mr. Kellahin.

CHAIRMAN WROTENBERY: Thank you. Then Mr. Kellahin, would you --

MR. KELLAHIN: Thank you, Madame Chairman.

CHAIRMAN WROTENBERY: -- like to proceed?

MR. KELLAHIN: Yes. We have in two separate filings submitted Sapient's exhibits. They are in a white binder. It was subsequently modified. I have revised the prehearing statement. I did so because I read the first one and I found it incredibly confusing and at moments incomprehensible. And so I took an additional effort to try to focus in on what I thought this case was about.

In addition, we have supplemented a couple of our displays, and we'll put them in the exhibit book at the appropriate time.

Mr. Carr and I are often fond of telling you that the Commission has expertise, and the first of us to get to the district court always refer to the special expertise of the Commission that cannot be disturbed by the district court judge, and the party taking the winning position here makes that argument.

Good or bad, this is not a legal case. It is a technical case. We can spend all morning talking about the process and the procedure of how we got here. Frankly, I think the process is confusing, I don't think it matters, I think we can cut to the regulatory issues, and once you decide on the technical points, a conclusion will flow naturally and logically to resolve this dispute.

We are dealing with the Monument-Tubb area in Lea County, New Mexico. We're going to show you a detailed geologic presentation so that you don't have to deal with the Sapient well in a vacuum. The Sapient geology and engineering testimony will show you in a comprehensive way where this gas well fits in the Monument-Tubb.

As you know by looking at the information, the Monument-Tubb has been developed from a regulatory perspective as an oil pool. In fact, there are multiple

gas wells in the oil pool already.

The pool rules, as you know, are 80-acre spacing for gas wells and oil wells, that you can have locations 330 from the side boundaries, and that there's a gas-oil-ratio limitation of 10,000 to 1. And that's the way it's been operated for years and years and years.

Along came Cross Timbers. In August of 1999, Cross Timbers recompleted the Barber 12 well -- that's a Sapient well now -- completed the Barber 12 well in the Tubb, and they got a gas well.

As part of their filings, they attempted -- and apparently believed that they had dedicated this well to the east half of Section 7. You and I all know that would be a nonstandard proration unit.

In addition, their well location is only 330 feet from the north line of Section 7 and encroaches towards Chevron-controlled acreage in Section 6, the southeast quarter.

They completed the well, and the Division District Office in Hobbs granted Cross Timbers the opportunity to produce that well by approving their C-104, and they did so. They then produced the well.

It is incredibly unfortunate that the District Office didn't recognize that the location was at an unorthodox location, didn't recognize that it had a

proposed acreage dedication that was inconsistent with the oil pool rules and inconsistent with Rule 104 for gas well.

The evidence will show you that the western boundary of the oil pool is at the northeast quarter of Section 7.

So as you look at this regulatory mess that we have all helped create, you have an inconsistency. And we believe it's arbitrary to provide for the Sapient well to be treated as a gas well.

And so in order to get that issue before the Division -- It wasn't the Division that brought it to Sapient's attention, it wasn't Cross Timbers, it wasn't Conoco, it wasn't Chevron. What happened is, after the Cross-Timbers well had been produced for almost a year, Chevron finally woke up to the fact that there was a gas well producing 330 from their boundary.

They then filed an administrative application in October, year 2000, sending notice to various people. And by January, then, during that period of November and December, Sapient became aware of Chevron's application and, in response to what-do-I-do-now?, learned that their well had deficiencies and approvals.

They didn't have a location approved, if it's a gas well spacing. They didn't have a spacing unit approved for an east half, northeast or the east half, east half of

the section or any of that kind of stuff, they just didn't. Sapient didn't know. Cross Timbers, if they knew, didn't tell them.

So Sapient, in good faith, walks into the mess. And once they recognized they had a regulatory deficiency, they initiated the Applications that you're now hearing.

We don't propose that you have to worry about the details of the Application. What we are asking you, though, is to use your technical expertise on some important issues.

The issue has to do with reservoir pressure, and it's critical that you make a judgment as to which of these experts has done the right methodology, the right analysis, and that his P/Z curves are correct, that his production profiles are correct, that his volumetric calculations are correct, and that his material balance of all this does justice to what we think the science shows.

The technical witnesses are going to be in disagreement, they're going to disagree on the porosity. At the hearing in March before Examiner Stogner there was uniform agreement on porosity to use in calculating the values for the Sapient 12 well. Chevron used 10 percent, Conoco and Sapient used 12 percent. Those numbers are going to change. And you're going to have to decide who's changed the numbers? Why? Does it matter? And if so,

what should you choose?

In addition, after Examiner Stogner issued his order in September that required that the well be shut in, that issue was appealed, the stay order was affirmed, and the well was shut in in October.

As a result of the shut-in, the evidence will demonstrate to you, Sapient took the opportunity to run a seven-day test on the well and has some very good, hard scientific evidence about the bottomhole pressure of that wellbore. They have then used that to calculate the various components to give you volumetrics and all the rest, and it is their firm conviction today that this well is capable of draining only about 60 acres.

Now, there's going to be disagreement from our opponents. They continue to advance that despite the new data the well will drain 160 to 165 acres.

So you need to resolve the pressure issue and the reservoir-engineering issues.

In addition you're going to have to decide, what is the appropriate porosity value and which of these two geologists went about the correct methodology to analyze that?

In addition you have to decide, is it going to be acceptable to treat this gas well on the western boundary of the oil pool as a conventional gas well on 160-acre

spacing? Or is it going to be logical and reasonable to match its rules with the rules in the oil pool where gas wells are currently being allowed to produce on 80-acre spacing?

That's what we're here to show you today.

The Sapient evidence book is incredibly detailed. It's certainly far beyond my expertise to understand those details. We will talk to you about as many of those things as you want to hear, and we will go through it first with the engineering testimony because, unlike many cases, we believe the engineering testimony is paramount to your decision. We want you to hear that first, and then we'll show you the geology and show you how the pieces fit together.

And that's our case.

CHAIRMAN WROTENBERY: Thank you, Mr. Kellahin.

Mr. Carr?

MR. CARR: May it please the Commission, we're here today because Sapient is seeking the retroactive adoption of 80-acre spacing in the West Monument-Tubb Gas Pool.

But the real reason we're here is that for over two years Sapient has ignored the Rules, for since September of 1999 they have been producing a well on a 160-acre spacing unit under the rules, a spacing unit in which

Chevron and Conoco and others own mineral rights, and Sapient has refused to pay these people for their share of the production. And they're here now today with a theory, hoping you will let them keep the production proceeds, the proceeds for production we submit they have drained from us.

And in support of their case, although we're only going to look at the technical case, you're going to get an interesting pitch from Sapient. You know, they're going to say that the OCD screwed up, it shouldn't have approved things, they're going to say that Chevron and Conoco were sleeping at the switch.

But when you look at the evidence at the end of this case, one thing is going to be very clear: Every single day, Chevron has been within the Rules of the Oil Conservation Division; every single day, Conoco has been within those rules. And every single day, Sapient has not. They're in violation of the rules.

Now, what are they in violation of? Well, Rule 12 of the Division provides, It shall be the responsibility of all the owners or operators to obtain information pertaining to the regulation of oil and gas before operations begin. That was not done.

What rules have they violated?

They have violated Rule 104.B.(2), which says you

must seek an unorthodox well location before this well can produce. That was not done, and the well for almost two years produced.

They violated Rule 104.D.(2), which provides that you must form a nonstandard unit before a well can produce. They did not do that.

And they seem to be confused, they seem to think today we're establishing a spacing unit for the well. All of New Mexico is spaced by Rule 104. The spacing unit in September of 1999 was 160 acres, and it is today. And it is the northeast quarter of Section 7, 160 acres substantially in the form of a square, being a legal subdivision -- quarter section, being a legal subdivision of the U.S. Public Land Survey.

There is a spacing unit today, and for two years we've owned part of that spacing unit, for two years we've been drained, and for two years we have not been paid.

Now, a month ago we were hoping to be here before you. And in November the case would have been much more complicated for you than it is today. You know, as with many things that, when you first look at them, appear to be very, very complicated, when you start to work on them you find that at the core the case is very simple.

And this case is very simple. There is one question you must ask, and all other things you must decide

will flow from that. And the question is, how many acres does the Sapient Barber well actually drain?

And we are going to have competing cases and competing technical cases. But today in December, it's a much easier case than it was in November because in the last month we have drilled and -- or we have completed the Matthews 12 well, "we" being Chevron. This well is 330 feet off the common line between the 160-acre spacing unit to which the Barber well has been dedicated.

And we have from this well pressure information, a new data point in the reservoir, we have sidewall core information, we have information on the mineral characters of the reservoir. And these bits of information confirm that the interpretation of Conoco and Chevron are correct.

Now, both of us, as Mr. Kellahin pointed out, have calculated drainage areas. They used PE porosity and calculate -- or the PE curve and calculated porosity, and they get 60 acres. We crossplot neutron density curve information, and we come up with 165 acres.

But the interesting thing is, we're all trying to figure out what the rocks say. We now have the rocks, and the rocks confirm the porosity calculations of Chevron and Conoco. And the minerals in those rocks -- anchorite, pyrite -- show that when you use a PE curve, it simply is inaccurate.

We also have pressure data, and the pressure data that we have isn't that different from what Mr. Kellahin thinks is new information. And what it shows is, this well -- with a very limited drainage area, if you believe Sapient -- with perhaps half of its reserves produced, has already drained all the way to the Matthews well and is going to drain substantially more than 60 acres by the time it ultimately is abandoned.

We're also going to show that the pressure information that they have used is simply incorrect. And it is incorrect, curiously enough, in a way that makes the reservoir much smaller than we believe it really is.

We also from the Matthews well have a new data point. You know, they have mapped the reservoir so it's perpendicular to the general trend. But when you honor the new data from the Matthews well, you see you have to pull your contours off to the west. And when you do, it shows what we've been saying all along, that the producible reserves are under our acreage, acreage which has been drained.

When it's all said and done, we really do believe this is going to be an easy case. And we do believe today, unlike a month ago, you have the kind of information that you need to make a determination on the Barber well and on this pool, and not do what Sapient because of the way the

data actually is going to sift out -- What they're going to try and do is ask you, Look, long, long ago and far, far away off to the east, and speculate about what happened before with other wells.

But the burden is on them to show that 80 acres is appropriate. And we submit, when the evidence is in you're going to find that it's absurd to think that anyone would suggest you adopt 80-acre spacing for a pool, where the only well in the pool with production history can drain in excess of 160 acres.

And when we get to that point, we're going to ask you to do what the Division did. We're going to ask you to deny the Applications of Sapient and find that the production has been in violation of the rules, is illegal production, tell them to keep their well shut in until the production proceeds are re-allocated to all the mineral owners in the standard spacing unit. That's the acreage -- the 160 acres which is dedicated to that well today, and it is the acreage which has been drained every day since they recompleted the Barber well in the Tubb.

CHAIRMAN WROTENBERY: Thank you, Mr. Carr.

Mr. Kellahin, would you call your first witness?

MR. KELLAHIN: Yes, ma'am. Call Mr. Kyle Travis.

CHAIRMAN WROTENBERY: Mr. Kellahin, before we get started, we received one exhibit that wasn't marked.

MR. KELLAHIN: That's 23-A, I think.

CHAIRMAN WROTENBERY: 23-A?

MR. KELLAHIN: It's a two-well cross-section?

CHAIRMAN WROTENBERY: Uh-huh.

MR. KELLAHIN: It's 23-A.

CHAIRMAN WROTENBERY: Yeah, that's it, 23-A. Thank you.

MR. KELLAHIN: Members of the Commission, Kyle Travis is president of Sapient Energy Corporation, he's a reservoir engineer. I'm going to ask him some introductory questions about how Sapient got here. We believe the record will speak for itself on the documentation. We have provided a chronological outline of those regulatory events as an appendix to the prehearing statement. Mr. Travis and I don't intend to spend a lot of time trying to cast blame on what happened and how we got here.

I do want to then focus his attention on the second part of the book, which is the petroleum engineering information.

But as you move through the book, you'll see that there's a tab, then you have a map. It will be a production map, and it's labeled Sapient Exhibit Number 1. If you wouldn't mind taking that out, unfolding it, and we'll use it as our locator for purposes of presentation. If you do not have that map, I have extra copies.

PAUL KYLE TRAVIS,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. For the record, Mr. Travis, would you please state your name and occupation?

A. Paul Kyle Travis, I'm president of Sapient Energy.

Q. Where do you reside, sir?

A. Tulsa, Oklahoma.

Q. Would you summarize for us your education?

A. Yes, I received a petroleum engineering degree from the University of Oklahoma in 1978. I worked for five years with Amoco production in drilling, operations and reservoir groups. In 1984 I went to work for an independent in Tulsa where I was production manager for 14 years. And then four years ago another gentleman and I formed Sapient Energy, where I've been president since that time.

Q. As part of your duties as president of Sapient, Mr. Travis, do you also manage and supervise land personnel?

A. Yes, land personnel and engineers, operations, are under my jurisdiction as well.

Q. In addition, have you worked with Mr. Bob Von Rhee, Sapient's geologist, in identifying the relevant facts concerning Sapient's Application?

A. Yes, I have.

Q. And have you and he looked at the technical data that's available to you?

A. Yes, we have.

Q. And based upon that data, do you now have certain conclusions and opinions?

A. Yes, I do.

Q. Have you provided to the Commission exhibits that in your opinion support those opinions and conclusions?

A. Yes, I have.

MR. KELLAHIN: We tender Mr. Travis as an expert petroleum engineer.

MR. CARR: No objection.

CHAIRMAN WROTENBERY: We accept Mr. Travis's qualifications.

Q. (By Mr. Kellahin) Mr. Travis, let's start with an introduction. Tell us who Sapient is, and how did you manage to get here at this point in time?

A. Okay, Sapient is a private company that, as I said before, was formed about four years ago. We are headquartered in Tulsa. We operate the Barber 12 well in Lea County, New Mexico, and obviously we're here to

determine the appropriate spacing for this well.

The well was originally recompleted by Cross Timbers into the Tubb formation in August of 1999 and made a gas well. The well produced for seven or eight months, until the time they sold the well, along with approximately 200 other properties, to a company called Falcon Creek in April of 2000.

Three months later, in July of 2000, Falcon Creek merged with Sapient Energy, so we became the operator of the well and continued to produce the well as it had done since Cross Timbers completed it.

Then in October, as Mr. Kellahin said in his prehearing statement, we received an application from Chevron for a location exception offsetting this well. We got to looking at the data and realized that we were not in compliance with the rules and regs for this well, so we set a hearing to determine, you know, what to do about this situation.

Q. Let's take a moment, Mr. Travis, and have you look at what we've unfolded as Exhibit Number 1.

A. Uh-huh.

Q. We'll come back and talk about the information later, but identify for us what we're looking at.

A. This is just an area map that outlines the Sapient lease, 280-acre lease, the Barber lease that's

included in Section 7 and Section 8. The Barber 12 well is identified up in the northeast northeast of 7. All the well locations that are spotted on this map are penetrations below 6000 feet.

You can see the location of the Matthews 12 well north of us, a little over 700 feet away. At the time this exhibit was created that well had just been proposed to be deepened; it had not actually been deepened. And as has been stated, that well has since been recompleted.

Q. When we look at the wells in Section 5, what is the pool that those wells are in?

A. Those wells are in the Monument-Tubb Pool.

Q. That's the oil pool, is it not?

A. That is correct.

Q. Do you know what the spacing rules are and well-location requirements for the oil pool?

A. Yes, it's 80-acre spacing with 330 standoffs for oil wells or gas wells.

Q. At the time Sapient merged with Falcon Creek Resources in July of the year 2000, were you aware of any of the approval deficiencies in the Cross-Timbers well?

A. No, we were not.

Q. When we look at how Cross Timbers was handling the production of the well, how had they been allocating it?

A. They had filed an acreage plat showing a standup 160, if you will. The east half, east half of Section 7, that is a -- as I said, that Barber 12 lease encompasses that, and -- were paying it based on the royalty in that lease as a 100-percent operator.

Q. At the time that you acquired this well and the other wells, were you aware that the spacing unit dedicated to the well by Cross Timbers was inconsistent with either the oil pool rules or the statewide Rule 104 as to statewide gas wells?

A. No, we were not.

Q. As part of analyzing your situation, in response to the Chevron attempt to offset the Cross Timbers well, you then investigated the circumstances?

A. That is correct.

Q. And it was after that, then, you became aware of the deficiencies in the regulatory approvals?

A. That is correct.

Q. Did you then take action to have an application filed to have the Division address those issues?

A. We did so.

Q. Did that matter come on to hearing before Examiner Stogner on March 1st?

A. Yes, it did.

Q. Let's talk about the technical portion of that

case in March.

A. Okay.

Q. Give us a summary of what was presented so that we have the background to understand what we're about to present.

A. Okay, we held the hearing in March. Engineering testimony was presented by both sides as to our estimates of the well's capabilities. At this time there was no bottomhole pressure data, there were no measured pressures. So most of the reserves were based on analysis of the declining production.

But to further complicate this task, the well had not yet established its natural decline. The well was being artificially restricted by maintaining a smaller choke on it, choking the pressure back, if you will, and so the well had not established a decline. So you had three engineers trying to project reserves on a well that was hardly declining. It was somewhat comical.

Engineers presented estimates of ultimate recoveries varying from 2.3 to 2.8 BCF and drainage areas ranging from 103 to 160 acres.

At that hearing, both sides presented estimates of average pay, average porosity, average water saturations in the Barber 12 well. Sapient presented their estimate, average porosity of 11.8 percent. Conoco stated at that

time average porosity was 12 percent. Chevron stated that the average porosity was 10 percent. So these -- although it varies a little bit, there weren't great differences in that.

Q. Based upon those calculations, then, Sapient determined an estimated ultimate recovery and calculated a drainage area for your well?

A. That is correct.

Q. And Conoco's engineering witness and Chevron's engineering witness did the same thing?

A. Right, we estimated 103 acres, and they estimated 160 acres.

Q. What has happened since the March hearing, Mr. Travis?

A. First of all, let me say that I think that the lack of technical data at that hearing, I don't think Mr. Stogner had any choice but to issue the order that it be 160 acres. We could not show that the well was going to drain a standup 160, and we didn't have any technical pressure data to support 80 acres, so I don't see how he had any choice but to default to the normal spacing for that depth.

You asked what has changed since March.

Q. Yes, sir.

A. Since March, the well has started its natural

decline. I'll present evidence that shows I estimate it's declining at about 43 percent.

The well encountered pipeline take problems during the summer, in June and July, and then we felt we developed a scale problem in August. We treated the well in September, restored production and got it back going.

The NMOCD issued the order which granted our location exception, but it placed the well on standard 160-acre spacing and ordered Sapient to shut the well in. We filed for this *de novo* hearing to appeal that decision and also filed for a stay to appeal the part of the order that said we had to shut the well in. That stay was denied, so the well was shut in on October 17th.

After a few days, it dawned on us that this presented an excellent opportunity to get a bottomhole pressure. The well was shut in, it had never been shut in for more than a day or two at a time, had never had a measured bottomhole pressure, so we thought, perfect, we'll get a bottomhole pressure.

So on October 22nd, after the well had been shut in for five days, we ran a pressure bomb and pulled that bomb two days later. That measurement gave us a seven-day bottomhole pressure of 1235 p.s.i.

That piece of data is the single best piece of reservoir engineering data that we have on this well, and

it opened our eyes to the estimated ultimate recovery for this well.

Q. Based upon that data, what do you now conclude is the appropriate size drainage area for the well?

A. I've calculated a drainage area of 60 acres. And this pressure point helped explain a lot of things, you know. The well was declining at 43 percent, and we couldn't understand why. We thought, based on its initial producing rate, that it was going to be a better well than that. But this pressure point showed us that the ultimate recovery was going to be less and that, indeed, the reservoir was smaller than we originally thought, the drainage area was smaller than we really thought, and that this was indeed the well's natural decline rate.

Okay. Then we prepared for the hearing in November, and everyone submitted exhibits again for the November 1st hearing. In the meantime, Mr. Von Rhee conducted a detailed log analysis of our well, much more detailed than I had done before. I had done -- performed my analysis based on two-foot increments.

He took the digitized log data, took it on half-foot increments, corrected for PE effect, corrected for change in matrix density. And doing all that, his number changed mine just a fraction. It went from 11.8 percent to 12.2 percent.

However, he also increased the water saturation, which in effect offset the increase in porosity so that the net effect on ϕh times 1 minus S_w was 4 or 5 percent. So minimal change in that, but a lot more detailed analysis.

In preparation for that hearing, Conoco now submitted an exhibit that their porosity for this well was 8.7 percent, whereas both companies had testified at the previous hearing average porosity at 10 percent and 12 percent, now they've got the same logs and they come up with 8.7 percent. I don't know why. They didn't present the support it, so I don't know why.

Okay. Then after that hearing was delayed, Chevron did deepen the Matthews 12 well, the north offset to our Barber 12 well. They deepened it, they logged it, they cut some sidewall cores, and they completed it. They've made a well that is producing approximately 500 MCFD; at least that's the data that they sent us on Saturday.

They also measured the bottomhole pressure in this well. They measured the bottomhole pressure for the well to be 1344 p.s.i., and it was still building at that time. Their well was clearly affected by our well. And I'm not surprised. If I take a 60-acre circle around our well, which is what I say our well is draining, you're going to exceed the distance between wells. So I'm not

surprised that their well is impacted by our well. They do have a higher pressure than we do, but they have been affected.

Okay, now we prepare for this hearing, and we exchange exhibits again. Sapient's porosity has not changed. But now we get their exhibits, and each time they've lowered their estimate of ultimate recovery -- they've had to honor the pressure data -- they lower their porosity a corresponding percentage. Now they've lowered their estimated ultimate recovery again, and surprise, their porosity is now 6.6 percent.

I'm sure they're going to offer some explanation as to why, but it sure is convenient that from the hearing in March to now they have lowered their estimated ultimate recovery 40 percent. And from their hearing in March till now, they've lowered their porosity 45 percent. It's very convenient.

Q. When we look at the technical case, Mr. Travis, give us a preview of the issues or points in the analysis that you would like the Commission to pay particular attention to.

A. This hearing is about drainage. You guys are here to assign the appropriate drainage for this -- appropriate spacing for this well. Basically, it's either going to be 160 acres or 80 acres. Conoco, Phillips,

Chevron, Texaco will tell you that 160 acres is the way to go.

We strongly believe that 80 acres is the correct and appropriate spacing for this field. It's more accurate, it's more realistic, it's more consistent with our past testimony, and it's more consistent with the spacing that exists in the field immediately offsetting this well.

In fact, let's pull out Exhibit 22.

Q. I believe it's Exhibit 22. We're going to take this out of order, if that's all right, and let's look at Exhibit 22. Identify this display for us, Mr. Travis.

A. This exhibit shows the Monument-Tubb West field, the field that the Commission put the Barber 12 well in, outlined in red over on the west side of the map.

And then the Monument-Tubb Oil Pool is outlined in green. You can see it's a very large field. It actually extends off the map to the east and off the map to the south. It's a Tubb field that is on 80-acre spacing for oil and gas wells. There are actually 15 gas wells in this field, 12 of which are operated by Chevron/Texaco, that the gas wells are spaced on 80 acres.

As you can see over on the western boundary of this field, it butts up right to the Barber 12 acreage, Section 7. This Tubb out here -- and Mr. Von Rhee can do a

much better job of explaining this reservoir, but I will just say that this is an extremely complicated, heterogeneous accumulation of Tubb interval here. It's not like a blanket pool, it's not like a Gulf Coast pool where it's all interconnected and you have one gas cap and everything is uniform.

You have these accumulations of gas that show up on regional highs, just as the Barber 12 is on a regional high over here, and these wells are comparable to our well. They typically average in the 2-BCF range, so they're in the same order of magnitude of type reserves that we're going to have from our well. It's just a very good analogy to our well. It's the same accumulation, it's the same Tubb accumulation, it's just the reservoir doesn't know that you've got this arbitrary line on a map up above it that says the Monument-Tubb field is here, it ends here.

There have been 24 extensions of this Monument Tubb field over the life as the field has grown, grown out from its original discovery back in the 1950s. So it's certainly an easy leap to say the thing extends on into our acreage as well and should be treated as such.

Q. As a reservoir engineer, Mr. Travis, do you see any regulatory reason to treat the Barber 12 well and the Matthews 12 well any differently than the gas wells are currently being treated in the oil pool?

A. None whatsoever. In fact, you set up, you know, the potential for some unfair competition if you don't. There in Section 5 to the northeast, the southwest quarter of Section 5, you've got two oil wells in that quarter section already. Amerada can drill -- because they're in the Monument-Tubb field, they can drill a third well in that quarter section and, in effect, put three wells in their quarter section to Chevron's one well in their quarter section, if you left us spaced 160, standard spacing. Without 80-acre spacings, they can achieve an advantage over there.

Q. Let's turn, Mr. Travis, to the portion of the exhibit book that deals with the reservoir engineering exhibits. If you'll find the white tab at the center of the book, immediately behind the white tab is an annotated list of the engineering exhibits, and then we start with Sapient Exhibit 13 and continue on.

Prior to that, Exhibit 1 is the locator production map, and Exhibits 2 through 12 represent regulatory documents, correct?

A. Correct.

Q. Let's start, then, with the engineering exhibits that are marked in the book 13 through 21. This all represents your analysis and your work product, true?

A. Correct.

Q. Let's start with the background on the Barber 12 well. Summarize for us its production history.

A. Okay, Exhibit 13 shows its historical production. As we said, the well was initially recompleted in August of 1999. It produced in the half-million-a-day range for a period of time, until January of 2000. At that time Cross Timbers, the operator, frac'd the well. Prior to then it had just been producing after a breakdown. They frac'd the well and increased the producing rate to over 1400 MCFD.

They produced the well at that rate, and as I said, they kept it choked back. It probably could have done more at that point, but they kept it choked back and produced it at those rates until April of 2000, at which time Falcon Creek bought the well. And Falcon Creek continued to produce the well and again was producing close to that 1400-MCFD rate for a couple of months, and then they had some problems with their separator. I don't know all the details, but they had some problems.

And then we merged with them in July and got them to open the choke back up, get the production back up, and it peaked for the second time in September, 2000, and then started declining at that point. It was really at that point that the well started its natural decline.

And it has now --

COMMISSIONER LEE: May I ask a question?

CHAIRMAN WROTENBERY: Go ahead.

COMMISSIONER LEE: You opened the choke when?

THE WITNESS: I don't know the exact date, but about -- It was a combination of getting the separator cleaned and getting the choke opened back up, in that September -- the month of September --

COMMISSIONER LEE: The month of --

THE WITNESS: -- of 2000.

COMMISSIONER LEE: 2000.

MR. KELLAHIN: Madame Chairman, we can provide Dr. Lee with the exact data if he would like that.

COMMISSIONER LEE: No, I don't want it, I just --

THE WITNESS: You see how the production dipped in July and August of 2000, the gas production? Are you looking at the table or --

CHAIRMAN WROTENBERY: We're looking at Exhibit 13.

COMMISSIONER LEE: Yeah, but I also look at --

CHAIRMAN WROTENBERY: Exhibit 20 is what Commissioner Lee is looking at.

THE WITNESS: Yeah, and it's hard to pick out exact months on that, but let's see, I've brought --

COMMISSIONER LEE: What kind of choke before that?

THE WITNESS: I don't -- It was a gradually --

They had choked it back and then were gradually increasing it, trying to maintain something in that 1300-to-1400-MCFD range. So as the well would decline, they'd crack it open a little more, a little more, a little more. And that's why you see for the first half of 2000, until they had the problems with their mechanical equipment, that production didn't decline very much.

COMMISSIONER LEE: And what is the choke now?

THE WITNESS: It's wide open now. Well, it's shut in now, but prior to the shut-in --

COMMISSIONER LEE: What do you mean, "wide open"? What size?

THE WITNESS: I don't -- You know, chokes, depending on the manufacturer --

COMMISSIONER LEE: 24 or --

THE WITNESS: No, it's either a half inch or three-quarters inch or a full inch. Probably three-quarters of an inch.

COMMISSIONER LEE: Thank you. When you go through the engineering data -- Can I ask a question now? Because later on, maybe I cannot put it all together.

MR. KELLAHIN: That's certainly acceptable to us, Madame Chairman.

CHAIRMAN WROTENBERY: Yes, go ahead then.

COMMISSIONER LEE: Then where did you get the

2597?

THE WITNESS: 2597 is the average of six drill stem tests for Tubb wells that were within five miles of this well. Since we didn't have a measured bottomhole pressure, and the operator when he recompleted this well, he didn't shut it in for any period of time, he completed it and turned it to sales immediately. So there was no good measured point on this well.

So we took drill stem tests from six wells, six Tubb wells in this area. We looked at more, but we discarded drill stem tests of wells that looked like they were either bad tests, depleted, that looked like they were virgin tests, and averaged those six wells.

COMMISSIONER LEE: Were those virgin tests at the same time?

THE WITNESS: No, they were not performed at the same time. We have -- There's actually a --

Q. (By Mr. Kellahin) Let's turn to that exhibit. If you'll turn to the back of the book, Exhibit 31-G, which is the last document stapled together, has a table showing the wells for which the initial pressure was --

A. Now, and you can see that although they weren't --

Q. Better let them find it, Mr. Travis.

CHAIRMAN WROTENBERY: 31-G?

MR. KELLAHIN: 31-G.

THE WITNESS: You can see that although they weren't done on the same date, but they were all done in the early life of this reservoir, they were done in the 1940s and 1950s and 1960s.

COMMISSIONER LEE: How far away is that?

THE WITNESS: They're all within five miles of our well. One off to the northwest --

COMMISSIONER LEE: Is there anything within this 20S-37E?

THE WITNESS: I'm sorry?

COMMISSIONER LEE: Is there any well here you used that?

THE WITNESS: With -- on -- There are some on this --

COMMISSIONER LEE: On here, on this map?

THE WITNESS: Let's see.

MR. ROSS: On Exhibit 1.

THE WITNESS: I don't think there's any -- Were any within the range of this map?

MR. KELLAHIN: Dr. Lee, if you'll turn past 31-G, the next page is a map showing the location of these wells.

COMMISSIONER LEE: Yeah, I'm asking if any of them is in this map.

THE WITNESS: And the answer is no. The closest

one -- the closest two are just up to the northeast, just to the north of Section 1, would be right up here, off the map, and then there's one in Section 9, just off the map to the east.

COMMISSIONER LEE: Okay, thank you.

CHAIRMAN WROTENBERY: Thank you, Mr. Travis, you can continue now.

THE WITNESS: Okay.

Q. (By Mr. Kellahin) Let's turn to Exhibit 14, Mr. Travis. Tell us what you did to compile the appropriate reservoir engineering data from which you could make your calculations.

A. Okay, this is a reservoir data sheet that I put together to show all our relevant data points that we used, so that when you're going back and reviewing the case, you can get most of your data off this sheet.

The bottomhole pressure initial, the 2597 that Dr. Lee just asked about, was the average of those six drill stem tests. Again, there were other tests in these wells that we chose to disregard because they were showing either depleted or bad tests, and we didn't feel they were relevant.

Z factor was calculated by some petroleum engineering software that I have that uses Standing/Katz correlations.

The BHP, bottomhole pressure, in October, the 1235 p.s.i., is the actual ending pressure at the end of that seven-day period, adjusted for mid-perf. Due to the size of the bomb that was run in the hole, we couldn't set it at mid-perf because of the mechanical restrictions in the wellbore, but projecting down to TD it added another 4 p.s.i., which gave 1235 p.s.i.

Now, in addition -- Well, let's go on, all right.

And you see the cumulative production of 808 million. I assumed an abandonment pressure of 300 p.s.i.a. for this well, which I think for this depth is reasonable.

You see the porosity figure of 12.2 percent that I've already mentioned before, that Mr. Von Rhee performed his detailed log analysis to come up with that figure.

Average water saturation, 27 percent, thickness 30 feet.

Temperature, 98 degrees, was measured on the bottomhole pressure test. I think I saw that -- Chevron, when they ran their test, I think I saw a measured bottomhole pressure of 103 degrees, so they're in close agreement there.

Gas gravity .68.

Liquid gravity -- This well actually makes a little liquid, and it's interesting that it -- this 37.1-degree oil, it's not condensate, and I think that's

due to the highly stratified nature of this reservoir.

Then the planimetered volumes. That planimetered volume comes off the next exhibit, Exhibit 15, and all I did there was -- You know, Mr. Von Rhee had prepared this isopach and said, Well, how much gas is in this quarter section, how much is in our 80s, you know, what -- how much gas is there?

And we determined by planimetering, using those porosity factors, and we determined that, if you jump all the way down to the volumetric data at the bottom, there's about 2.2 BCF gas in place in the 80 acres that is the east half of the northeast of 7. We calculated from this isopach 1.6 BCF gas in place on the west half for a total of 3.8 BCF in this quarter section. And if our well is only going to cum 1.3 or 1.5 BCF, we're clearly not going to drain this section.

Now, I might also add, and I'm sure Conoco will try to make hay with this, that when this isopach was prepared, the Matthews 12 was not deepened. So we did not have a data point for that Matthews 12. Since it was deepened -- and we just got their logs on Saturday -- Mr. Von Rhee has calculated that there are 32 feet of pay in that Matthews 12 well.

So yes, their well -- I don't think it will swing the thick, I think all it will do is expand the thick out

to the west and -- yeah, that -- probably the whole south half of Section 6 there is probably productive.

Q. When you look at the appropriate well density for the wells in this immediate vicinity, in your opinion is one well on 160 going to be sufficient?

A. No, it will not. I think Conoco's testimony will even show that.

Q. Let's turn to Exhibit 16, Mr. Travis --

A. Okay.

Q. -- and first address the volumetric calculations.

A. All right. And again, we used the same input that was off that reservoir data sheet of 30 feet, 12.2-percent porosity, initial bottomhole pressure 2597. We calculate -- From that data we calculate the original recoverable gas in place of 741. You all can go through this, I don't want to bore you.

But let's -- The gas in place is 815 MCF per acre feet. Then you incorporate that with the planimetered volumes. We show the planimetered volumes down there at the bottom, again, what we have in our 80s, in our 80, what Conoco has in their 80, and what is there in the total northeast quarter of Section 7. This is just how the data off the reservoir data sheet was calculated. This is the detail of that calculation.

Q. Let's turn to the bottomhole pressure test. In

your opinion as a reservoir engineer, was the test appropriately conducted?

A. Yes, it was.

Q. Describe for us the testing procedures and the test results.

A. Okay. As I said, the well was shut in for five days at the time we initiated the test. We ran a lubricator, of course, to keep the well shut in while we were running it in the hole. They set it above the seating nipple and hung it off for two days.

Now, normally we don't have the benefit of seven days' pressures. We didn't have it for the March hearing. If we we'd had a seven-day shut-in pressure at that time, you know, we probably -- we would at least have had some technical data.

The State doesn't require a seven-day shut-in. The State typically requires either one-day or two-day shut-ins, and even then just shut-in tubing pressure at the surface is adequate for reporting. But here we have the benefit of superior data.

All right...

Q. How do we utilize that data?

A. We take that into the material balance calculation, and we calculate drainage.

Q. Okay, let's do that.

A. All right.

Q. If you'll turn to Exhibit 18, show us how you do that.

A. All right, we take a starting pressure, divide it by Z to get an initial P/Z. That's our starting point.

Then we take our second pressure point, the 1235 p.s.i. from the seven-day shut-in, get a new Z, a new BHP over Z. That gives us our two points. From those two points we extrapolate to an ultimate recovery and a gas in place. The calculations are shown there, and then we'll show it graphically on the next exhibit.

But one thing I probably ought to point out, you notice there's two drainage areas at the bottom. That's because I take my gas in place -- The P/Z doesn't lie. That's the best source for estimating ultimate recovery. If you've got good pressure data, that's the best estimate of gas in place and estimated ultimate recovery. It's just rare that you have good pressure data.

All right, so I take that, and I'm confident with that number. And I say, Well, there's two ways to look at this. We've got our wellbore that says the average thickness is 30 feet, and we have a planimetered volume of this area that says there's so much MCF per acre-foot.

So under one scenario I use just the wellbore data, the 30 feet constant, and that's the bottom

calculation that calculates 60 acres. If you use the planimetered volume, then you get that the well is only draining 53 acres of this 80.

So either way. I mean, 53, 60 acres, I mean, they both are in the same vicinity and both point to 80-acre drainage.

Q. Let's turn to Exhibit 19 and show the data in a graphical form.

A. Yeah, that's the graphical depiction of the material balance, and you can see the two points, the initial P/Z on the left, the second point at the 808-million-cubic-feet point, extrapolating down to an original gas in place.

Q. You've got your volumetric calculation, you have your P/Z calculations. Now what did you do?

A. Okay, one other thing I did, I said, okay, well, that well was still building, even though it had been shut in for seven days, that well -- the pressure was still building minutely. So obviously it was not at average reservoir pressure at this point.

So there's two things you can -- Well, you can plot that in a semi-log plot and extrapolate out to a theoretical P*. P* -- and Dr. Lee, I'm sorry if I bore you, and correct me if I'm wrong -- P* is a theoretical value at infinite time, assuming an infinite drainage.

But in real life, wells don't drain infinitely, so you don't have infinite time. And what would happen in real life is, if left shut in long enough, that extrapolation -- that pressure data would break over and level out at some average reservoir pressure. And there are means to calculate that average reservoir pressure.

And we took the method that Dr. Lee uses in his textbook and calculated a P average of 1248 p.s.i. So that's only 14 -- let's see, 13 p.s.i. more. So I re-ran numbers using that 1248, and not surprisingly it didn't change -- it changed the numbers so small that the -- I mean, it still calculated out 60 acres, so insignificant change. But we did go through that exercise. You know, if you use P*, you'll get an erroneous point.

Q. Let's turn to the plot of the production information, the production decline curve, Exhibit 20.

A. Let me --

CHAIRMAN WROTENBERY: Commissioner Lee has one question here.

THE WITNESS: Uh-huh.

COMMISSIONER LEE: In the four hours you built the initial pressure, you've almost recovered 90 percent of your pressure, right?

THE WITNESS: You're looking at the --

COMMISSIONER LEE: The very first four hours.

MR. KELLAHIN: Exhibit 17.

COMMISSIONER LEE: What is the permeability, do you think?

THE WITNESS: That is not -- That's deceiving, because, see, that's only four hours into this test. It was shut in five days prior to that. But nevertheless, the permeability is probably between 1 and 2 millidarcies.

COMMISSIONER LEE: One and 2 millidarcies.

THE WITNESS: And this is after frac. You know, this well was frac'd too.

COMMISSIONER LEE: So how long did you -- You built it back up to 1217 after five days?

THE WITNESS: Correct.

CHAIRMAN WROTENBERY: Thank you.

THE WITNESS: Okay. Let me say one other thing before we move on to Exhibit 20.

You know, we analyzed the porosity in this Barber 12 well in detail, and Mr. Von Rhee will discuss that.

When we got the exhibits from Conoco, Chevron, Texaco, Phillips, the Seven Sisters, we got -- you know, and saw the 6.6 percent, we said, you know, How on earth could they come up with a number that low? And we looked and we said, you know, Well, come up with the most conservative analysis that you can, and ignore changes in matrix, just come up with the most conservative analysis

that you can. And so Bob said okay.

And he went through using that digitized log data and came up with 8.4 percent, lowered our porosity from 12.2 to 8.4. He said, that's as low as I can get.

And so I said, all right, let me run that number. So I took that number, ran that through my calculations using the same material balance data, and I get 80-acres drainage.

So whether it's -- you know, the endpoint is still the same, whether it's 60 acres or 88 acres, it still points to 80-acre spacing.

Okay, now I'm ready to move on.

Q. (By Mr. Kellahin) All right, let's look at Exhibit 21. I'm sorry, Exhibit 20 and then 21.

A. Exhibit 20 is a plot of that production data, and the gas is shown in red, the oil in green, and you've got a fine red line drawn through the production that is my projection of this well's natural decline. That extrapolation is a 43-percent decline.

You can see that the well falls off the curve. In July it drops below it -- Excuse me, in June and July it drops below it, although July is a lot closer. We had pipeline curtailments during that time. Then you see it really falling in August and September. The last two points on this curve are August and September because we

did not have October sales at the time I created this exhibit.

And that is -- As I mentioned before, we had problems with it, we were working on the well, did several treatments on it, trying to get the well back, and actually did have it back producing on this curve in October, and then the well was shut in, and has remained shut in since that time.

So using this projection, we go to the next exhibit, 21.

The well has produced an ultimate of 808 million so far, a cumulative production of 808 million. Taking its producing rate of 800 MCFD, an economic limit of 20 MCFD -- and incidentally, I changed that economic limit. It's insignificant to the reserves, but it's more realistic. I was running 10 MCFD before, and that was when gas was at five -- over five dollars an MCF. Now that gas is below three dollars an MCF, I've lowered my economic -- or raised my economic limit to account for that.

Using the decline rate of 43 percent -- that's effective decline -- gives a nominal decline, the a, of 56 percent, and calculates out an estimated ultimate recovery of 1.3 BCF, which also agrees with my material balance.

If you go back to Exhibit 18, under the calculations I estimate the ultimate recovery to be 1.326

BCF. This is 1.315 BCF, so they're in close agreement.

Then you calculate drainage, acre drainage area, from this ultimate recovery and you get 59 acres, again in that same 60-acre vicinity.

MR. KELLAHIN: Madame Chairman, that concludes my examination of --

THE WITNESS: I've got a few --

MR. KELLAHIN: Hang on just a --

THE WITNESS: -- I'd just like to conclude, if I could.

MR. KELLAHIN: Let me see where you are on the outline, Kyle.

THE WITNESS: All right, I was wrong, that concludes my testimony.

MR. KELLAHIN: We move the introduction of Mr. Travis's Exhibits 1 through 21.

MR. CARR: No objection.

CHAIRMAN WROTENBERY: Exhibits 1 through 21 are admitted into evidence.

You also talked about 22. Do you want to wait on that one or --

MR. KELLAHIN: I'd like to have my geologist further authenticate the technical data.

CHAIRMAN WROTENBERY: Mr. Carr?

MR. CARR: Thank you, Ms. Wrotenbery.

CROSS-EXAMINATION

BY MR. CARR:

Q. Mr. Travis, if I understand it, when you acquired the Sapient well it was because had acquired the interests of Falcon Creek; is that correct?

A. We had merged with Falcon Creek, that's correct.

Q. At that time, was there an opportunity for you to do any due diligence to determine whether or not wells were in compliance with the Rules of this Division?

A. No, there was not.

Q. The interests that we're talking about here were acquired by Falcon Creek from TMBR/Sharp; is that right?

A. No, they acquired them from Cross Timbers.

Q. From Cross Timbers, I'm sorry. And at the time of that acquisition, was there an opportunity to do due diligence to determine whether or not this well was in compliance with Division Rules?

A. They performed some due diligence. They acquired over 200 properties, and they could not -- there was no way they investigate every well, whether it had adequately complied with Commission filings. There was the approval of the well to produce. I don't know -- you know, since I wasn't there I don't know if they found that or not. There just -- When you do a merger of that -- or an acquisition of that magnitude, you can't get into that kind of detail.

Q. So at the time of that merger, it's fair to say you hadn't checked to see if, in fact, there was a problem with the Rules of the Division?

A. That is correct.

Q. You understand today that statewide spacing for gas wells in this area would be 160 acres, do you not?

A. Yes.

Q. And in your testimony and in prehearing statements filed in this case it's been suggested that Chevron delayed a year responding to the recompletion of the Barber well in the Tubb formation; are you familiar with that argument?

A. I'm not following you.

Q. Is it your position that Chevron waited for a year before they responded to the recompletion of the Barber well?

A. They waited for over a year after the well was completed -- recompleted, before they filed -- oh, no, no, before they filed for their location exception they actually tested a well, another Matthews well, and found it too tight to produce before moving on the Matthews 12 Application.

Q. But it's not your testimony that Chevron was doing nothing during that first year?

A. I don't know what they were doing.

Q. And you're not testifying about what they're doing; is that fair to say? Or were doing?

A. Correct.

Q. You discovered this problem when you received a copy of an application from Chevron to recomplete the Matthews 12, 330 off the south line of Section 6; isn't that fair to say?

A. That is correct.

Q. And when you received that application, that's when you first took some action and filed the Applications, the original Applications, that resulted in this hearing; isn't that fair to say?

A. Repeat the question.

Q. When you received the notice from Chevron that they wanted to recomplete the Matthews 12 -- the Number 6, the well was 300 off the line?

A. No, the Matthews 12.

Q. The Matthews 12, when you received the request to re-enter that well as an unorthodox location 330 from your lease, that is the first time you were aware you had a problem; is that correct?

A. That is correct.

Q. And you responded to that, did you not?

A. Yes, we did.

Q. And you responded, one, by filing Applications

which have resulted in hearings for pool rule changes --

A. Correct.

Q. -- this hearing today?

You also initially objected to that location --

A. That is correct.

Q. -- did you not?

And because of your objection to the Chevron well, that application was also set for hearing, was it not?

A. That is correct.

Q. They filed that application in mid-October -- Chevron filed the application in mid-October to re-enter the Matthews 12, correct?

A. Correct.

Q. And you objected about a week later, correct?

A. Correct.

Q. That matter was set for hearing in late January of 2000; is that not correct?

A. I would have to look it up. I have no reason to doubt that that's correct.

Q. And you withdrew your objection, however, so that case never went to hearing; isn't that right?

A. That is correct.

Q. And you withdrew your objection two days before the hearing; isn't that correct?

A. Correct.

Q. And during that period of time you produced the Barber well every day, did you not?

A. That is correct.

Q. And you drained reserves from the offsetting property every day, did you not?

A. I don't know at that point that we were draining reserves off their property.

Q. But you were able to drain the reservoir without a competing well --

A. Correct.

Q. -- in that 90-day period; isn't that correct?

A. That is correct.

Q. You're not complaining about the timing on the data that was submitted to you last week, are you?

A. No, I am not.

Q. When you objected to the proposed Chevron well, you knew they were only trying to be as close to the common lease line as you already were; isn't that right?

A. Correct.

Q. But you objected to their being from the lease line?

A. Correct.

Q. I want to be sure too that I don't misunderstand your testimony. You have testified that there were certain

forms that were approved by the Oil Conservation Division which --

A. That is correct.

Q. -- have led to this problem in some degree?

You're not saying that the OCD has failed to do anything that they should have done?

A. How could you possibly draw that conclusion from my testimony?

Q. Well, I just wanted to be sure, because there were some indications that if the OCD hadn't done this, we wouldn't be in this situation.

A. I don't think anyone on our side has said such.

Q. You're not saying that Chevron or Conoco were remiss in not taking some action earlier because of the --

A. Could they have acted quicker? I think they could have.

Q. Do you think they might have been able to act quicker if anyone had given them notice that the well was on a nonstandard unit?

A. Could they have?

Q. Uh-huh.

A. I don't know. I don't know what -- they testified -- I don't know when they became aware of it. They testified at the first hearing that they didn't know when they became aware of it.

Q. You do know that when you saw the approval of an unorthodox well location you provided notice to offset operators; isn't that correct?

A. Correct.

Q. Are you aware of any notice being formally presented to either Chevron or Conoco prior to the time --

A. Well, I don't know. Would they have gotten notice that a -- or -- I don't know what the noticing -- what the State sent them.

Q. Do you know of any notice that you sent to them?

A. We did not, we weren't operator of the well at the time.

Q. When you sought the unorthodox location, you were the operator of the well?

A. Correct.

Q. And you provided notice at that time?

A. Correct.

Q. You ran the bottomhole pressure test on the well after the well was shut in?

A. Correct.

Q. Did you run the pressure gauge in the well prior to the time that you actually shut the well in?

A. No, we did not.

Q. When did you put the pressure gauge actually in the well?

A. As I testified to previously, five days after the well was shut in.

Q. You also testified you did not go to the perforations, and I think you testified that was because of the packer; is that right?

A. Packer and seating nipple.

Q. How did you adjust those figures to get to an actual bottomhole pressure?

A. We took pressure stops on the way out of the hole, to get a gradient and project it down to mid-perf.

Q. Do you have any idea if there were fluids in the well below the gauge?

A. There was no -- No, there was no indication that there was any up to that point, and we could not say whether there were or were not below.

Q. In earlier testimony in prior cases you testified, I believe, that the Barber well produced condensate --

A. No, I did not testify.

Q. You did not?

A. No.

Q. Has it always been your position that it is producing oil?

A. No, at the last hearing I did not know whether it was oil or condensate. Now I've confirmed that it is oil.

Q. The initial pressure measurements that you used in your calculations, were you testifying that you had actually gotten those pressures from some other wells and then averaged them; is that how you approached that problem?

A. Are you talking about the drill stem tests?

Q. I'm talking about the initial pressures that you got on the reservoir.

A. Right, we took industry-available data and took the pressures from that industry-available data and averaged them.

Q. And were you using wells that were at the same depth as the perforations --

A. They were --

Q. -- in the Barber well?

A. Not exactly the same depth. They were fairly similar.

Q. Were adjustments made on those before you averaged, or did you just average them?

A. No, but after we got Conoco's exhibits and where they normalized that to depth, we looked at that this weekend, and it lowered the average maybe 50 p.s.i. Fairly insignificant.

Q. In terms of how you approached calculating a porosity in the reservoir, should I defer those to the

geological witness?

A. Yes.

Q. You would agree with me, I think, that we have a gas well, whether we're producing some oil or not?

A. By New Mexico standards, yes.

Q. And as the pools now stand, the West Monument-Tubb Pool is classified as a gas pool; is that right?

A. That is correct.

Q. Are you suggesting that, in fact, the Barber well is an oil well?

A. No, I did not suggest that.

Q. You are asking this Commission to apply the oil well pool rules to the gas well in this gas pool; is that right?

A. That is correct, the same as they treat the gas wells off to the east.

Q. In doing that, would you agree with me that if the Commission concludes that the Barber well actually drains 165 acres, that it wouldn't make much sense to create an 80- -- put it in an 80-acre oil pool?

A. I would not necessarily go that far, no.

Q. So if they conclude the Barber well is a gas well draining 165 acres, you would think they might want to put it in an 80-acre-spaced oil pool?

A. It's possible, and I'll -- You're dealing with

hypotheses. I think I'll be able to explain that later after I see their case.

Q. And you're planning to testify again?

A. I may or may not.

Q. In calculating the number of acres that you're going to drain with the Barber well, you get 59, 60 acres, something like that?

A. Correct.

Q. That translates into ultimately a drainage radius of about 900 feet?

A. Correct.

Q. At the present time, we're already seeing the effects of drainage in the Matthews well, which is 700-plus feet --

A. Correct.

Q. -- isn't that right?

You produce 50-percent-plus of the reserves that will be recovered out of the Barber well?

A. Correct.

Q. When you put these numbers together, doesn't it appear to you that when you produce 100 percent of the recoverable reserves, you're going to be out a lot farther than 900 feet?

A. No, I think that's what the material balance shows, is that it will drain -- if it drains in a circle,

which nothing ever does, but if it were, it will drain out the 912 feet.

Q. If we look at your exhibits -- and I have just a few questions to clarify things that are probably clear to everybody in the room but me -- Exhibit Number 14 --

A. Yes.

Q. -- this is the reservoir data sheet.

A. Right.

Q. The plainimetered volumes, those plainimetered volumes are based on the isopach prior to receiving the Matthews data; is that what you said?

A. That's correct.

Q. You have, from your testimony, assigned 32 feet of pay to the Matthews well based on that data?

A. Based on which data?

Q. I believe you said that your geologist had looked at the data on the Matthews well and had assigned 32 feet of pay to that well?

A. Correct.

Q. And accordingly, that would expand the thick toward the Matthews well; isn't that right?

A. That would expand a thick, correct.

Q. And I believe it was your testimony that because of this, it appeared that the southeast of Section 6 would be productive; was that your testimony?

A. Actually, it may be the whole south half.

Q. Doesn't the additional Matthews point also suggest that the west half of the northeast will also be productive?

A. West half of the northeast of what section?

Q. Of Section 7.

A. Yes, right, and we're not going to get those reserves with our well.

Q. If we look at Exhibit Number 20, the production plot --

A. Okay.

Q. -- the curve that you have drawn on this production data is based on points that run, it looks to me, like the first red square sometime in September or thereabouts of 2000 and run forward through probably July --

A. Correct.

Q. -- of this year; is that fair?

A. Correct.

Q. You then started to work on the well -- There were from June to July, I believe you testified, some pipeline curtailments?

A. Correct.

Q. That pulled the curve down at that point in time?

A. Correct.

Q. Did you use that period of time to project the ultimate decline for the well?

A. No.

Q. If we go August and September, it drops far below the curve. That's when you were actually acidizing and recovering that load; is that right?

A. Correct.

Q. At the time of this hearing on the stay, it's my recollection that you testified that you anticipated the well to come back up?

A. Correct.

Q. And I believe you testified today when it was shut in, it was at approximately 800 MCF per day?

A. No, it was at -- the actual shut-in at that point was -- or excuse me, the actual flow rate was about 840 MCFD at the time of shut-in.

Q. And was it your testimony that that point would put that number on the curve?

A. Well, it would actually put it slightly above it. But I think what we are seeing -- I allowed for the fact that the well had been shut in for so much of August and September that you often have after shut-in periods kind of a springboard effect where you'll get flush production higher, and then it will come back to its natural decline, and that's what I was forecasting.

Q. I believe at the stay hearing you testified that you had anticipated the well could go as high as 1.1 million; is that right?

A. We had hoped that -- That is correct. We had hoped that it would get back up in excess of a million a day.

Q. Is that still possible?

A. It's -- No, and I'll tell you what has changed since that point. The -- You'll recall we presented an exhibit at that time that had the well still building, and then in the interim it flattened out so it ceased to build prior to its shut-in, and I can show that to you graphically if you'd like to see it.

Q. I don't need to see it but my question was, was there something different that --

A. And there is, yeah, it had flattened out.

MR. CARR: That's all I have, thank you.

CHAIRMAN WROTENBERY: Commissioner Bailey?

COMMISSIONER BAILEY: I have no questions.

CHAIRMAN WROTENBERY: Commissioner Lee?

EXAMINATION

BY COMMISSIONER LEE:

Q. Would you please look at the Exhibit Number 20?

A. Yes.

Q. You don't have data beyond -- because it's shut

in, correct? You don't have data beyond the red line?

A. Correct.

Q. Then you say the current production rate in the next exhibit is 800 MCF per day?

A. Correct.

Q. And this scale, how can you say it's --

A. Okay, this scale is MCF per month.

Q. MCF per month.

A. If you look at the 10,000 on the left, 20,000, 24,000 a month would be approximately 800 and would -- Do you see that?

COMMISSIONER LEE: Okay, no more.

CHAIRMAN WROTENBERY: Any redirect?

MR. KELLAHIN: No, ma'am.

CHAIRMAN WROTENBERY: Thank you very much for your testimony, Mr. Travis.

MR. KELLAHIN: Madame Chairman, if you desire to proceed, I'd like a short two- or three-minute break so we can get the next witness set up.

CHAIRMAN WROTENBERY: Okay, that sounds fine. We'll break for just a couple minutes.

(Thereupon, a recess was taken at 11:25 a.m.)

(The following proceedings had at 11:30 a.m.)

CHAIRMAN WROTENBERY: We're ready when you are, Mr. Kellahin.

MR. KELLAHIN: Thank you. Call at this time Mr. Bob Von Rhee.

ROBERT W. VON RHEE,

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. Von Rhee, for the record, sir, would you please state your name and occupation?

A. My name is Robert Von Rhee, I'm a petroleum geologist.

Q. And where do you reside, sir?

A. Tulsa, Oklahoma.

Q. Summarize for us your education.

A. I have a master's degree in geology from the University of Illinois, 1977. I'm a certified petroleum geologist under the AAPG.

I was employed by Exxon the first four years of my career, spent a number of years after that working for independent oil and gas companies in Oklahoma City and in Tulsa, and of late I run a geological consultancy in Tulsa since 1998 specializing in development geology, the exploitation of reservoirs, and for the last year I've been the chief geologist at Sapient Energy.

Q. Did you testify as Sapient's geologic expert at

the March hearing before Examiner Stogner?

A. Yes.

Q. And have you been responsible for evaluating the geologic data for the Monument-Tubb Oil Pool plus the data surrounding the Sapient Barber 12 well?

A. Yes.

MR. KELLAHIN: We tender Mr. Von Rhee as an expert geologic witness.

MR. CARR: No objection.

CHAIRMAN WROTENBERY: His qualifications are accepted.

Q. (By Mr. Kellahin) Mr. Von Rhee, let's go from the general to the specific. By general, I'd like you to give us a geologic interpretation of the entire, and let's start with the oil pool. I'm proposing to you, sir, that we look at Exhibit Number 22. The geologic exhibits and maps that we're about to look at represent your work product, do they?

A. Yes.

Q. And the conclusions that you'll make from these displays represent your conclusions?

A. Yes, they do.

Q. Identify for me what is marked as Exhibit 22.

A. Exhibit 22 is a structural map on top of what I call the lower Tubb limestone. It's an internal limestone

bed within the Tubb formation.

Q. In addition to all the exhibits that you're sponsoring, did you prepare the summary of geologic exhibits that's annotated just ahead of this exhibit?

A. Yes.

Q. What's the significance of the color code?

A. The color code just allows your eye to quickly ascertain the areas that are structurally high, which are the warmer areas in yellows and oranges, and the areas that are structurally low which are the cooler colors, in the greens and blues.

Q. What have you chosen to be the datum point on which to prepare the structure map?

A. The datum point is, as I just mentioned, the top of the lower Tubb limestone. It's an internal bed, an informal designation.

Q. Is it a reliable geologic marker for --

A. Yes.

Q. -- you?

A. The lower Tubb limestone, one, it has a high degree or correlation confidence, it exists over a wide area, and it is within the interval that most of the Tubb completions are perforated. In other words, it usually lies somewhere below the top of the perfs and above the base of the perfs.

Q. Let's turn to Exhibit 23; setting this one aside for a moment, let's look at 23.

A. 23 or 23-A?

Q. I'm sorry, what?

A. 23 or 23-A?

Q. Let me ask you, what's the difference between 23 and 23-A?

A. Exhibit 23-A will locate a stratigraphic cross-section which we will introduce.

Q. All right, and that is the only difference?

A. No -- Yes, that is the only difference --

Q. Yeah.

A. -- I'm sorry.

Q. So let's look at 23-A so that we can see the line of cross-section. I apologize, Mr. Von Rhee. So 23-A is a replacement for 23, and the difference is, you've constructed a line of cross-section?

A. That's correct.

Q. All right. What are we looking at when we look at 23-A?

A. We are looking at the same structural maps that were presented in Exhibit 22. I should mention on both of these maps, wells that have been completed and have indicated an initial potential in the Tubb formation have been so designated by the small tan circle that you see

under the well symbol, so you can see which wells are completed in the Tubb formation.

In addition to the structure, there is noted a stratigraphic cross-section. It's labeled E-E', runs west to east across the field. It begins at the Barber 12 well on the west end and ends at a well in Section 12 on the east end of the cross-section.

In addition to that, you can ascertain there are three areas within the Monument-Tubb, and if you take a moment, flip back to Exhibit 22, which does not have much overprinting on it, if you locate the green boundary of the Monument-Tubb field, which is basically the top and bottom of the page and right to left, you'll note that within it there are three areas of local structural highs. There's one at the top of the page, one at the right-hand side of the page, and then this small one down in Section 16. And these are small closed structures within the Monument field and within the Tubb formation.

Now, if return to Exhibit 23-A, kind of keeping in mind where those little local structures were, you'll now see that there's kind of a light red-pink shading that overprints these structures, and that shading is indicating areas where Tubb Oil Pool completions have produced with cumulative GORs in excess of 100,000. In essence, they're gas wells.

In my research in this area, looking at the completion reports for these various wells, you would see a high degree of variability in the oil or liquids that were produced with them. Some of the wells reported initial oil gravities in the 40-degree range, some reported them as high as 71 degrees, what we would think of as condensate. We see a real complex relationship.

I do have some data on these wells that have produced these high GORs, and I think --

Q. Let's see the relationship of what you characterize the gas wells in the oil pool. Let's keep the locator map, 23-A, out, and if you'll look to the tabulation page, Exhibit 24 --

A. Okay.

Q. -- that represents what, sir?

A. Let me get it. Exhibit 24 lists the wells that are posted within these shaded areas in the Monument-Tubb Pool. These data are from the commercial production data, the *IHS/Dwight's* production data.

And the calculation of the wells' cumulative GOR shown in the right-hand-most column -- excuse me, the column labeled "CUM GOR" next to that, is a column that calculated the produced GOR by these wells over their past 12 months' production. When a well produced gas and reported zero oil, in order not to have to use infinite, I

just assigned it that large 9 million number that you see there. That's representative of zero oil production in the last 12 months.

Q. On this table you have 15 wells that appear to be gas wells?

A. That's correct.

Q. Did you do any further research to show how the Division Rules classify these wells?

A. Yes, we retrieved for these wells and a few other wells in the field that were of interest the filed C-105 completion forms. Sometimes we only had a C-107, I believe; some of the older wells had that. We also obtained the C-106, the acreage designation; did I get that right?

Q. C-102, C-102 is the acreage --

A. Okay, the C-102. And finally, we retrieved the C-116s, the annual GOR testing reports for these wells.

And we noted of these 15 wells -- This is nothing new. This field was discovered in 1959. In 1962, I found the first gas well reported as such, and it's continued as such to this day. You'll notice on the tabulation that in the fifth well down, which is identified as the Texaco Weir B Number 7, it was completed in 1962. The regulatory form designated it as a gas well to the NMOCD at that time.

It continues to produce now with no oil

production, and the C-116 filed for that well this past summer indicated zero oil production from the Tubb zone. It kind of looks like a gas well.

That well is located, by the way, in the right-hand-most gas area. You'll notice that I've given these areas some names to kind of separate them, and the right-hand-most one is just called the Weir gas area. And that well is down in the southwest quarter of Section 12. You'll see Weir B Number 7 and a little tan dot. It's on the cross-section E-E', and that well is located there.

In 1964, Conoco established special field rules for this Monument-Tubb field, which resulted in 80-acre spacing and 330 setbacks. They requested a producing GOR limitation of 6000 at that time, but the Commission was a little leery about what that would do to reservoir energy and assigned 4000.

In 1994 Texaco applied to increase that GOR, and they were successful and the GOR limitation was raised to 10,000.

And then we have had wells drilled -- If you'll go back to the table, you'll notice that wells have been drilled in the 1960s, in the 1970s, in the 1980s. In fact, in 1994, just two weeks before Texaco's Application, they completed a direct offset to the old 1962 Weir B 7 well. It's on the list, it's the one at the top of the page, the

Weir A 14.

And on the map it's in Section 12, and you'll notice it's just northeast, a direct 80-acre offset to the old 1962 well. This well was completed in 1967, and its C-105 indicated an initial production of over 2 million feet of gas a day and zero oil and zero water. And it's now cum'd over 1.8 BCF of gas on an 80-acre basis, next to a well that was completed in 1962, so...

Q. What kind of well density is being used over in the Weir area where you've identified this first gas accumulation?

A. Well, you'll notice I also put some numbers that give you some idea of the magnitude of the gas and oil production in these areas of gas wells.

The pink area we call the Weir area. You can kind of see that you can envelope it by a 640-acre square. Let's just call it one section. There have been nine gas completions in that section, that equivalent section, if you will, and seven still produce. That's equivalent to either a 91-acre spacing on seven active wells or a 71-acre spacing on nine wells. And they've extracted nearly 20 BCF of gas by this type of development in the Monument Pool.

Q. Let's go up to the Cooper area to the north and have you discuss that area.

A. The Cooper area is very similar. There's a local

high area, and you can see that two of the wells in that area are gas wells, they are on the list on Exhibit 24. It's the two wells where the operator says Me-Tex Oil and Gas, the State A 1 and the Cooper Number 1. Now, both of those wells have cumulative GORs in excess of 100,000. You can see that the State -- in fact -- and then the -- both of those wells, their C-116s filed this past summer indicated zero oil production from the Tubb zone.

And at the time of their completion, Me-Tex filed the State A as a gas well on its regulatory forms, and it filed the Cooper Number 1, I believe, was -- It was filed as an oil well by Me-Tex at that time. But by the nature of its production it's fairly evident that it was a gas well. In addition, I believe it reported a -- high-gravity liquids with its initial completion.

And if you look at the tan dots in there, you'll see that this spacing is about 80 acres. In fact, right along the section lines it looks pretty much like 40 acres. But there's a fairly high density of wells. And these two wells have now produced over 2 1/2 BCF from this area.

Q. Let's look lastly at the Van Etton area of the oil pool, over to the southwest in Section 9.

A. Okay. The Van Etton area -- I will point out that one of those wells, the Number 14 that's in the gas area -- you see it lies a structurally low spot. That well

has an unusual surface elevation posted on the log. It's out of synch with the neighbors by about 50 feet, and I did not get a topographic map to try to correct that, but I'm fairly certain that there's about a 50-foot bust in elevation on that, and you would find it structurally high and not structurally low.

However, there's been four gas completions -- or four wells down there with cumulative GORs in excess of 100,000, and it's a small area, and those wells have produced about -- a little over 1 1/2 BCF of gas down there.

Q. When you as a geologist study the oil pool, do you see any relationship between structure and wells that have higher gas-oil ratios?

A. Well, I think it's fairly obvious on just these two maps here that the wells with higher GORs are located on the local structural highs.

Q. Characterize the kind of reservoir we have here.

A. The Tubb reservoir is about 200 feet thick, as we're using the designation in our hearing today. By that I mean, all parties, Chevron, Conoco, Sapient, agree on what the top of the interval is, and we agree on what the base of the Tubb or the top of the Drinkard would be.

Now, if you look back in March, there was some discrepancy between the parties, that Chevron/Conoco had

different top of Drinkards, but we're all on the same page.

If we were to project that across the Monument-Tubb field and examine the rocks in that interval, we see -- and we'll show this on the cross-section -- the interval is about 200 feet thick. And I've examined available core data as I could get it, its descriptions, mud logs as I could find them, we have one in our well. I've looked at logs that give you lithologic information like LDT curves, the PE curves. We were able to review Chevron's sidewall core data that they took in the Matthews 12, and as much information as I could about what is this 200-foot interval composed of?

It's a series of bedded rocks, it's not massive. It's composed of beds that range from, you know, probably less than a foot to over 20 to 25 feet thick. The lithologies range from limestone to dolomite to sandstone and various mixtures of those, sandy dolomite, dolomitic sandstone.

And if you look at the lateral continuity, you find that there's a gross continuity within the 200 feet that you can carry across a wide area, so you can say that the upper Tubb and limestone in the east side of the field is correlative to the west side, and you certainly can identify the 200-foot interval with precision.

But you do notice as you move laterally that some

of these rocks that are more limey in one area become more dolomitic in another area. In the two cores that I had descriptions for on the cross-section, I noticed that one well had a sandstone, and the next well over the sandstone was gone and there's dolomite. You see lateral variation in lithology and in the presence and absence of beds.

When you get to the detailed level, then you try to look at each one of these beds in its own little discrete porosity. You find that each bed's porosity zone may not be continuous from well to well. In fact, as the geologist I'm left looking in the subsurface, and I can only go so far because I can't see the in-between area, between the wells.

So I see a reservoir that's complex lithologically, it's complex stratigraphically, and it's heterogeneous, it's not homogeneous and uniform.

Q. Let me show you Exhibit 24-A, and I have color copies if you didn't get color copies in the exhibit books.

CHAIRMAN WROTENBERY: Thank you.

Q. (By Mr. Kellahin) Let's use Exhibit 24-A, Mr. Von Rhee, to illustrate the structural relationship of the gas and the oil in the pool.

A. Okay. Let me preface this exhibit. I'm charged with describing the reservoir in a way that's useful to its interpretation. I'm charged with correlating our well to

this reservoir as it exists in this part of New Mexico, and I'm also charged with developing data for the reservoir.

In doing that, and being a geologist, I formed a characterization of the reservoir that it's pretty clear in my head but it's not often clear in other people's heads -- right, Mr. Carr? -- and so this is an attempt -- this diagram is a schematic. It shows relevant data that we've observed in the Monument-Tubb oil field.

And moreover it shows a concept that I hope will be meaningful on the nature of this reservoir. And I mentioned that I'm able to look at well by well and I can make extrapolations, and if I did simple extrapolations everything would correlate to everything else. I can't see between the wells, it kind of looks that -- but every -- that's pinched out places arrive, but I can see a porosity zone on one well, I can see the same porosity zone in a well that's 80 acres away. I really don't know if they're connected.

So as part of my interpretation I have to go as far as I can with the subsurface geology.

Then you have to look at the production. And the production is what allows you to then take your geologic interpretation a next step. And this cross-section kind of goes through that effort.

In this field, if you look at the cross-section,

there's an upper light blue, and you see the color variation. Those represent large subdivisions of the Tubb.

The green represents discrete porosity intervals that exist within the Tubb. And these are intervals that in my mind are maybe two feet, 15 feet thick, these types of things. There are very -- lots of other intervals that I'm sure are below the resolution of our measurement tools.

You can see that the structural relief of this accumulation is about 182 feet from the highest-perf'd Tubb well to the lowest-perf'd Tubb well. So you have a reservoir that's 200 feet thick, but structurally it's not even displaced by its own thickness. See, it's almost flat. There's very little structure to it relative to its own thickness.

Next, you notice that -- I've shown two orange bars on there. They represent a -- kind of a typical Tubb completion for some of these wells. And in this instance I was examining -- kind of using the Cooper area as a guideline. You find wells that are adjacent to one other, for instance in the Cooper area and in the Weir area. And when you examine these two wells -- and by adjacent I mean within an 80-acre basis -- and you find that for instance, if you look on the schematic, a gas well, for instance, has a high-perf gas and a low-perf gas, and we use that for information about the reservoir. The oil well, for

instance, that's right next to it has the same type of information.

And what we find in the Cooper area and in the Tubb -- in the Weir areas, that -- for instance, in the Cooper area the structural displacement from the highest known oil perf exists 132 feet, I think, higher structurally than the lowest known gas perf, which is a discrepancy. It's a huge overlap.

Similarly in the Weir area, we see about a 102-foot overlap between the highest known oil and the lowest known gas. So we have this bigger than 100-foot overlap of perforated interval.

And sometimes it looks like these wells are correlative because we see the same porosity zones, but we see dramatically different production, a gas well versus an oil well.

The significance of this analysis and the analysis that I've done with the gas wells and so forth and so on is that this is a poorly segregated accumulation of hydrocarbons vertically. We have lots of overlap between gas and oil production. It's also a poorly segregated accumulation laterally. We go from GOR 20,000 oil wells to GOR infinity within very short distances and very little structural relief.

The description of the porosity zones that you

see on this schematic represents the information that as a geologist you gain by coupling the production attributes with the rocks and what you see. That's why you'll notice from the oil well to the gas well, if you let your eye follow some of those green areas, you'll see that they truncate and reappear in the gas well. Similarly, some of these zones get very narrow, very thin, and then thicken again.

And when you're only sampling a small percentage of the earth -- and if you've ever made a calculation as to what percentage of the earth have you sampled when you've drilled 18 or 25 wells in 640 acres, each well only samples this little teeny footprint, you're not really taking a very big sample. But we do the best we can.

And that schematic, I would hope, gives you some idea of the vertical heterogeneity and complexity of this reservoir and the lateral heterogeneity and complexity of this Monument-Tubb reservoir.

Q. Let's take the E-E' cross-section so we can link the Barber 12 well back to the oil pool, if you'll take a moment to unfold that. It's Exhibit 29, it's 29-A in the information.

Draw for us, Mr. Von Rhee, the geologic connection from the Barber 12 well as we move east through the oil pool. Can you do that with this cross-section?

A. Yes, you can.

Q. Let's have you do it.

A. The cross-section is stratigraphic. It means that all the wells are lined up on a common geologic datum, and it's been identified on the map, you'll see it, and it's also the top of the lower Tubb limestone. It's the datum that was mapped structurally on the Monument-Tubb field.

On the left-hand side is the Barber 12 well, and you can see demarcations of the gross intervals within the Tubb. What I use is the Tubb sandstone, upper Tubb limestone. You have to develop a lingo that's meaningful that allows you to map things and give them names.

You can see that our well is completed in the lower portion of the overall Tubb interval. By the way, the blue line, the blue shadings, represent this group's determination of the top of the Tubb interval and the base of the Tubb interval or the top of the Drinkard. All right, it should be consistent with the cross-sections by all parties as it occurs in the Barber 12.

See, the boundaries of the Tubb have been correlated eastward throughout the field to Section 12, the Weir area, by the blue. The internal divisions identified or correlated black lines that you see that go left to right, and in addition the top and bottom of perforated

intervals has been highlighted in orange.

You can trace the rocks very confidently across the Monument-Tubb field. I can find absolutely nothing in the subsurface that tells me that the Barber 12 has now encountered different rocks than exist to the east.

Q. Let's do this on a two-well comparison. If you'll set aside the E-E' cross-section, leave it in place or fold it, but I want to draw your attention to Exhibit 24-B, which is a two-well cross-section.

COMMISSIONER LEE: 24-B, 24-B.

THE WITNESS: It should look like this.

Q. (By Mr. Kellahin) All right, this may be easier to work with, Mr. Von Rhee. First of all, show us the two wells. We've got the Barber 12 on the left, correct?

A. That's correct.

Q. And what's the other well?

A. The Barber -- Excuse me, the right-hand well is the Chevron/Texaco Weir A Number 14. It exists on cross-section E-E'. It was the well drilled in 1994 and completed as a gas well with zero oil production. It has now produced 1.8 BCF.

Q. Are the two wells geologically correlative?

A. Yes.

Q. Describe the completion analogy between the two wells.

A. The comparison is a high degree of geological correlation insofar as this is the Tubb interval. It has similar major divisions within it. It has less similar, more variable porosity variations from well to well, which is to be expected. It has variations in bed thickness within the gross intervals, which is to be expected in this type of reservoir.

Q. Let me ask you this. If I'm going from the Matthews 12 area to the Weir area or the Cooper area, am I going to change my completion intervals?

A. Yes.

Q. And why would I do that?

A. Each well encounters a different version of the Tubb reservoir, with porosities, perms and objective zones specific to that drilling point in this large accumulation.

Q. When I look at the completion analogies, do I see completions in similar type of rock?

A. Yes, and dissimilar. I mean, you see completions throughout the Tubb intervals. These two particular wells, once again I've shaded the top to bottom of the perforated interval. You'll see that they are certainly correlative geologically. These two particular wells are perforated over analogous intervals, the lower part of the Tubb, and they have very similar production attributes. You'll note the oil and water production from the two wells is nearly

identical, and the gas production in the Weir 14 -- of course, it's higher than the Barber 12, but it's also seven, almost eight years old. So it's produced for a longer amount of time.

Q. Can I geologically distinguish the Matthews 12 well from the Weir 14 well?

A. No, they're in the same rock, the same Tubb formation.

Q. Do you see any geologic characteristic of the Matthews 12 well that would cause you to believe it ought to be treated any differently from a regulatory perspective than the gas wells in the oil pool?

A. No, none whatsoever. It's -- In fact, the Tubb formation was deposited without knowledge of all the little regulatory divisions, you know. It was deposited over the Central Basin Platform, which is a regional feature in New Mexico and West Texas. It has amazing similarities that extend from all the way down into the Central Basin Platform in Ward County, and up into this area of Lea County. In fact, it's still a complex lithologic interval when you can trace it up into the Texas panhandle.

And so understanding the Tubb formation as it exists in a field that's 738 feet away from our well is extremely relevant to the issue today.

Q. Let me have you summarize your conclusions about

the Tubb formation in general, and then we'll go into the localized examination of the geology for the Barber 12 well. Let's have you characterize the Tubb formation.

A. I think -- The Tubb formation is geologically complex. It's heterogeneous both vertically and laterally. It has gas wells in it, wells capable of producing GORs in excess of 100,000. These gas wells occur on local structural high areas. There's poor vertical segregation between the gas and oil and poor -- you know, which is consistent with this kind of reservoir, that's what we would expect.

The gas wells have produced on 80-acre spacing, and they appear to have produced with no impairment in terms of reserves. The Weir 14 was drilled offsetting a 1962 well, 33 years later, and encounters another 1.8 BCF of gas out of the Tubb that would have gone unrecovered.

The principles of heterogeneous, complex reservoirs are that they will yield wells that are not capable of draining large areas. They're great density drilling targets, we love to find them because we can drill lots of wells, because we continue to find unrecovered reserves.

There's no geological separation that I can find between the Barber 12 and any of the other Tubb wells that offset us to the east in the Monument-Tubb Oil Pool. And

the Barber 12 production to date, as I've shown on the two-well cross-section, is virtually identical to other wells that produce in the Monument-Tubb Oil Pool.

MR. KELLAHIN: Madame Chairman, that concludes my chapter of the general pool description, and we're ready to move to the next topic, which is the localized geology for the Barber 12 well. It's a convenient place for us to stop if it is for you.

CHAIRMAN WROTENBERY: We'd like to go on about 30 more minutes if that would be okay with you.

MR. KELLAHIN: All right.

Q. (By Mr. Kellahin) Let me turn to the next topic with you, Mr. Von Rhee. Let's go to the localized geology. Let's start with your Exhibit 27. Is that the one you have?

A. Yes, sir.

Q. All right. On Exhibit 22, Mr. Von Rhee, you gave us the overview of the Tubb Structure, and now we're specifically looking at the localized geologic interpretation?

A. That's correct.

Q. When you get to the Barber 12 area, there is some differences either in detail or in information. Do you see this?

A. Oh, yeah, yeah, okay.

Q. All right, so when we move to a more detailed investigation of the Barber 12, you've added information and details that weren't present in Exhibit 22?

A. That's correct. The Exhibit 22, the area structure map, is a computer solution to the structural problem. The computer algorithms, which are quite reliable, accurately depict what wells are higher and what wells are lower.

Exhibit 27 is the same data, but now it is in the local area of the Barber 12. It's on the same horizon, except now it's been contoured by hand. I've allowed the little analog computer in my head to work on this problem and to a little more thoughtfully map the structure as it occurs right in the vicinity of the Barber 12, and therein are the differences.

Q. Do you have a concept for this portion of the reservoir, or any portion of the Tubb, that would cause you to believe that it is anything other than a solution gas drive reservoir?

A. Boy, I'm versed in reservoir engineering principles, but I'm not a PE.

Q. I'm talking about from a geologic concept. Let me ask you a simpler question.

A. Yeah.

Q. Geologically, should we be concerned about having

the Barber 12 as a gas well being upstructure from the Marathon oil wells in the north half of the southwest quarter of 5 as you move to the northeast?

A. No.

Q. Okay. Geologically, why shouldn't we be concerned?

A. I do not think the influence -- Excuse me, let me rephrase. I do not think -- It's my opinion the Barber 12 and the Barber wells in Section 5 are not influencing one another in their production. There's too much reservoir variability, heterogeneity, in fact perhaps even a fault, a local fault.

Q. So when the reservoir engineer gives you production data, you can satisfy yourself as a geologist that there is a limited geologic extent by which that well is affecting adjoining wells or adjoining properties?

A. That's correct. In a reservoir of this nature, over the field you do not have good interwell communication. Any two wells might just fortuitously encounter porosity zones that are in communication, and they may exhibit those characteristics. But as a whole it's a poorly communicated field, and wells do not necessarily influence the wells adjacent to them.

Q. Give us the structural conclusions, then, from Exhibit Number 27.

A. Exhibit 27 shows a small closed structure just to the northwest of the Barber Number 12. I have -- It has local variations, you see the contours move around. You see that I've mapped two small closed areas, you see I've also mapped a small fault. So there's details at this level that you didn't see at the other level.

Q. Let's turn now to the isopach and look at the reservoir distribution. That's Exhibit 28.

A. Exhibit 28.

Q. What is the isopached interval, Mr. Von Rhee?

A. The isopached interval is of footage of Tubb reservoir exceeding a porosity cutoff.

Q. All right, let's talk about your cutoffs. I know that we have inadvertently left off the cutoff data from the exhibit. Would you supply that for us so we know what you're using for cutoffs?

A. Because this reservoir is complex and multiple lithologies, it presents a problem. If we try to ascertain a single porosity cutoff then we're saying that each rock member, whether it's a sandstone, limestone, dolomite or some other complicated lithology, reaches a point where it can contribute reserves as soon as it crosses that threshold. So we've got a problem, we have different lithologies. In my experience, different lithologies yield commercial fluids at different porosity thresholds.

The other problem we have is in trying to map in the area, we have an area that's had wells for some 40 years, and we have different vintage logs. The dominant logs are density porosity logs and sonic porosity logs. So if we establish cutoffs in different lithologies, we also have to be able to make an equivalency between the two types of logs across those lithologies.

Now, I made an effort, a performance-based evaluation, looked at wells and recoveries and what were the porosities to try to zero in on what is a good porosity cutoff for the dominant lithologies in this area, which were dolomite and limestone.

For the limestones I used the 4-percent porosity cutoff. For the dolomite intervals I used a 10.3-percent porosity cutoff. I found that on equivalent sonic logs as empirical analysis if I assessed cutoff thickness -- excuse me, porosity thickness, with my density cutoffs in the different lithologies. I had two wells that had both density and sonic logs. By comparing those I was able to ascertain that in order to reproduce the same amount of thickness that you would map for those wells, my density cutoffs of 4 percent and 10.3 percent had to be 52 microseconds and 58.5 microseconds, respectively. You can see it's a little nasty problem.

But I tried to develop some things that were

based in the performance of wells in the area, the comparison of wells with two different logs in the same rock, and then apply it uniformly to this area with the different vintage logs and the different lithologies. So it's not your usual single-cutoff map type of thing.

The amount of rock that was analyzed was restricted to the three principal members of the Tubb that the Barber 12 is completed in. That's a gross interval of about 70 feet.

Q. Let's go now to the portion of the display that shows the distribution and the orientation of this isopached interval. Discuss and describe that.

A. Of course, the contour lines themselves show you the distribution, the shape, the trends of the interpreted porosity thicknesses. Because again I see patterns in these squiggly lines that a lot of people don't see, I highlighted the portion of the map in excess of 30 feet so you know that that's a thick and it has a shape in the direction indicated, that's not a thin. I've also got some thick and thin labels on there.

In addition, it seemed to me that we had no information in the southern portion of our acreage. In March of this year it was pointed out to Sapient that Conoco had deepened the well, the Barber Federal Number 1 that you see in the southwest quarter of Section 7.

However, we were unaware of it. They supplied a portion of the mud log and drilling time logs for that well at that time, and apparently that was all that was available for that well. Open hole logs were never run due to mechanical problems.

I did discover why we were unaware of it. The commercial data never reported its total TD. It only reported its final plugback TD, which was below the threshold that I was searching for, 6000 feet. So it existed in the data, we found it later, because it was not identified properly.

At any rate, that provided us a data point for porosity in a key direction to the southwest that we thought would be significant.

Also, I expanded -- a new well or two were drilled in Section 5 to the northeast. The two wells that you see in the northeast quarter of Section 5 were drilled since last March. I was only able to get a well on one of one of those logs -- I mean a log on one of those wells. But again, trying to add new interpretation, new data, make the interpretation a little more meaningful.

I did go through a process that I think is logical and sound to estimate a net porosity thickness from the mud log on the Barber Federal Number 1, which is the 40-foot data point that you see.

In addition, I did not have time to adjust this map to the new data on the Matthews Number 12. We received that data Saturday morning and much other data, and we just flat ran out of time.

However, I was able to analyze the Matthews 12 well in the same way I analyzed all the others and ascribed a 32-foot net thickness of this Tubb interval to that data point. And it would shift the thick interval that you see highlighted in red, it would shift it to the north -- northwest, excuse me. It doesn't necessarily invalidate any of the other interpretation, it just changes it.

Q. Let's go to Exhibit 31-G and address the data, the drill stem data, that was utilized by Mr. Travis in his calculations on the initial bottomhole pressure estimates. If you'll turn to that, it's in the back of the exhibit book.

Did you participate in the search for this data?

A. Yes, I did.

Q. Tell us the method and why you have reached the conclusion you've reached.

A. First of all, I gathered every file that we possibly had at Sapient Energy relative to this well, from every office that we have, leafed through that one piece of paper at a time, and could find absolutely no record of a measured pressure in this well's life, early in its life.

So we were quite frustrated by that.

Therefore, we embarked on an effort to ascribe an initial bottomhole pressure to this reservoir as best we could by finding some good DST data, and that's what this table represents.

In the course of mapping the Monument-Tubb area, the large map you saw, we encountered lots of Tubb DSTs. These particular DSTs are all relatively old, in the early history of the field. These DSTs also reported gas to surface, which is -- to me says that we've got a good test, we're actually measuring the fluids that are in the rock. One of them didn't report gas to surface but reported a very healthy flow pressure that, as Mr. Travis suggested to me, is that must have had some fluid to surface if its flow pressures got that high. And so he thought that that, then, his pressure, would also be representative.

At the time that this exhibit was prepared we were doing many things. These pressures were simply tallied up and an average of that reported bottomhole pressure calculated.

It's brought to our attention by Conoco -- Conoco's rehashing of these data, by the way. They will -- They have submitted an exhibit that reproduces these data, and really presented a better way to work these data.

Now remember, if you're concerned about the

structural position of the data, the entire Tubb accumulation only has a structural relief of about 182 feet. So all these data points are pretty close together in the subsurface structurally. They're also relatively close together in time, and they are separated from one another in space. So it's unlikely that they would have influenced one another when they were measured.

And a better method to analyze this data would be to normalize each of these measurements into a pressure gradient that is calculated to the midpoint of the test and then look at the midpoint of the Barber 12 -- Excuse me, average those gradients and apply that average gradient to the midpoint of the Barber 12 well.

Now, I have done that for this data set, and the pressure that I obtained the arithmetic that way was 2546 pounds. We originally used the number you see on the exhibit of 2597 pounds. The difference of 51 p.s.i. is 2 percent. Now, I'm not an expert on the measuring tools used in the late 1950s and 1960s, but I think that's within the error of the measurements themselves.

Conoco, in their exhibits submitted for this hearing, discovered another DST in one of these wells, the B 24. It was not of record on the data that I had, but it was in the Tubb interval. Now, it had a -- and it was taken as a DST just up the hole and above the interval that

you see reported here for the B 24.

It looked reasonable. There was no reporting of what the surface action was. We don't know if any fluids were recovered or gas or so forth, but the pressure was -- 2390 pounds reported in that test, is one of the lowest here. But if you incorporate that new data point in these data set right here, the effect is to lower the calculated Barber 12 bottomhole by 75 p.s.i., which is below a 3-percent difference. So it's another data point, it's at the low end of the spectrum.

Now, we've eliminated some DST tests and pressures -- there were pressures of 1500 pounds, 1800 pounds, gas-cut mud, things of these nature. As I mentioned, I'm not a PE, but I don't know of any situation that would cause DST pressure to be too high. But I know of many reasons the DST pressure would be too low. In fact, these data here, because some of them have very short shut-in periods, 15 minutes and 30 minutes, may well be kind of a minimum pressure for the reservoir. If these pressures had been allowed to build up for 120 minutes or longer, they might have been higher.

So we excluded some more pressure points that I think were appropriately excluded, and we included DSTs that I think were appropriately included, in trying to establish the appropriate gradient and the most likely

original bottomhole pressure for the Barber Number 12, because Cross Timbers wouldn't measure it.

MR. KELLAHIN: Madame Chairman, that concludes my examination of Mr. Von Rhee.

We move the introduction of his Exhibits 22 through 31.

CHAIRMAN WROTENBERY: Okay, and does that include some of the exhibits you have not discussed here today.

MR. KELLAHIN: We would like to put them in the record. For the sake of being concise, we have not talked about the additional cross-section.

CHAIRMAN WROTENBERY: There were 31-A through --

MR. KELLAHIN: It's 22 --

CHAIRMAN WROTENBERY: -- -F, for instance?

MR. KELLAHIN: Yeah. Would you like me to have the witness identify those for the record? I can do that.

CHAIRMAN WROTENBERY: That might help, just because we've had some substitutions in the last couple of days, and I want to make sure we're looking at the same ones you did.

Q. (By Mr. Kellahin) All right, Mr. Von Rhee, we have concluded with Exhibit 28. The next exhibit in the book is 29. It's the A-A' cross-section. That's the one displayed on Exhibit 28, correct?

A. That's correct.

Q. All right. There is no material geologic difference in your opinions or in conclusions if we were to discuss Exhibit 29?

A. No.

Q. 29-A is the big E-E' cross-section that we did discuss.

Exhibit 30, then, is a discussion of the data where you got your porosity cutoffs, and we've described that as part of your testimony in Exhibit 28?

A. That's correct.

MR. KELLAHIN: Okay, that should complete the package.

CHAIRMAN WROTENBERY: Okay, so the way I've got it down, we had 22, 23-A. There was a 23 originally, but we substituted 23-A --

MR. KELLAHIN: Yes, ma'am.

CHAIRMAN WROTENBERY: -- for the original 23. 24 and 24-A, 24-B. There was a 25 and 26 that we didn't discuss.

MR. KELLAHIN: This went to Mr. Von Rhee's testimony about the gas wells in the oil pool.

Q. (By Mr. Kellahin) Do you want to touch on those briefly for me, Mr. Von Rhee, so we have information in the record? There are two pages.

A. Oh, yes. Exhibit 25, just a table that

summarizes the production from the 15 wells identified with cumulative GORs in excess of 100,000 commercial data.

Exhibit 26, to the extent that I had a subsea point for the lower Tubb limestone picked and a cumulative GOR for a well calculated, they were crossplotted, and Exhibit 26 is a crossplot of the cumulative GOR of the Tubb versus the subsea lower limestone: What's the relationship between structure and GOR?

And you have a somewhat fuzzy but definite relationship of higher GORs at higher structure and lower GORs at lower structure.

CHAIRMAN WROTENBERY: So what I've got here is the list of exhibits you're offering into evidence: 22, 23-A, 24, 24-A, 24-B, 25 through 28, 29, 29-A, 30 and 31-A through -G.

MR. KELLAHIN: Yes, ma'am.

CHAIRMAN WROTENBERY: Any objection? Mr. Carr, any objection to the introduction --

MR. CARR: No, no objection to the admission of the exhibits.

CHAIRMAN WROTENBERY: Okay, then those exhibits will be admitted into evidence.

And it is time now, I think, to take a lunch break. How long would you like to break? Do you need more than an hour?

MR. CARR: No.

CHAIRMAN WROTENBERY: Okay, then we'll start back up at 1:30.

(Thereupon, a recess was taken at 12:30 p.m.)

(The following proceedings had at 1:30 p.m.)

CHAIRMAN WROTENBERY: Okay. I believe, Mr. Carr, you're up.

CROSS-EXAMINATION

BY MR. CARR:

Q. Mr. Von Rhee, this morning you testified about how you had calculated porosity values, I believe, and that's --

A. I think I calculated as to what my cutoffs were.

Q. Okay, I thought you said you had used a density curve, that you used a PE --

A. Oh, to that extent, that's correct.

Q. And you used a PE curve, and --

A. I didn't testify to that yet, but --

Q. Are you planning to testify about that later?

A. If you ask me, I will.

Q. All right. Why don't you tell me how you calculated porosity?

A. Where, what well?

Q. Well, let's say the Barber well.

A. The Barber Number 12?

Q. Uh-huh.

A. Okay. The Barber 12 is a neutron density log. The log is the lithodensity tool, so it also measures a parameter we've come to know as photoelectric factor, PE. The PE curve is mineral-specific, has certain values for certain minerals. These particular rocks are dominated by dolomite, calcite, quartz, minerals that have known PE responses.

And at the time that we began analyzing this log, which was over -- since March, as Mr. Travis said; I started my analysis after March -- you could see that we had a complicated body of rock. And with that tool, the PE enables us to make an estimate of the matrix density of the rocks, which we could incorporate into the density calculation of porosity.

The other thing about this well log is, it's in a gas zone, and it's in complex lithologies. And the neutron curve in complex lithologies is calibrated to read limestone porosity, it's measured to do that. And as soon as it departs from seeing a limestone, it has to be corrected. In dolomites it measures porosities too high, in sandstones too low, in gas zones it tends to be reduced, the neutron response is suppressed.

It's known for its -- In gas zones, one also would say that because the gas is a lower density, and the

density tool measures the bulk density of the rocks, that the density tool reads too high because of gas.

It's been my experience that the neutron curve is much more highly affected by environmental factors than the density curve is, in all the years that I've mapped rocks, with the exception that in extremely depleted gas reservoirs, you will see a bona fide increase in density porosity. And you do tend to see in gas zones, the neutron curve often gets suppressed to the extent that it's just not that reliable, it loses its character. And yet the density curve will retain character and appear to be reading porosity of the rocks. If you simply crossplot those two, you're ignoring the mineral-specific response of the PE curve.

So with those things in mind, I chose to analyze the porosity of the Barber 12 by incorporating the PE curve to estimate a matrix density and use the matrix density compared to the bulk density that the log measured and calculate a porosity for the Barber 12.

Q. You had a neutron curve on that well, did you not?

A. That's correct.

Q. You had a density curve on the well?

A. That's correct.

Q. Did you not use a neutron -- Did you come up with

a neutron density crossplot curve for that well?

A. Yes, I did.

Q. And did you use that?

A. No, I didn't.

Q. When you talk about the PE curve, do you make any adjustments to that curve, or is that a curve you can just utilize? Did you make any adjustments to it when you used it?

A. What kind of adjustments are you speaking of?

Q. Well, I don't know. I mean, I'm trying to see if you can take the data off the log and use that, or if you make adjustments. I mean, when I listened to you it sounded like if you were in a depleted gas reservoir you'd have to do something with the neutron curve, and I just wondered, could you use the PE curve as you found it in this well, or did you have to do something to it?

A. You faded on me, I'm sorry.

Q. Could you use the PE curve as you saw it on the log in this well, or did you need to do something to it, to adjust it some way, in your opinion?

A. I used the data on the Barber 12 without any corrections to what was measured.

MR. CARR: Okay, that's all I have. Thank you.

THE WITNESS: Uh-huh.

CHAIRMAN WROTENBERY: Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. I hope you can help clear up some confusion. Do you know if the Barber 12 was fractured?

A. Yes, it was.

Q. So would you say that there are enhanced vertical communications between those producing intervals?

A. There must be some additional reservoir accessed and communication is improved, because the well's performance improved. What's the description of that? It's my understanding of fracture stimulation that the fractures are oriented vertically, and so it's quite probable that we have accessed some porosity compartments that perhaps we don't see at the wellbore, that exist at a little distance, that we've accessed those porosity compartments.

The fracture stimulation also will provide a better pathway for gas to get to the wellbore. It creates a larger surface exposed to the wellbore because you have broken the rocks like this instead of just a perforation. So we've accessed more of this complex reservoir by frac'ing it.

Q. You've described the Tubb as 200 feet thick, embedded with intervals 1 to 25 feet thick. Is there much vertical communication between these beds as you've

described them, other than through mechanical fracturing?

A. Let's take the problem. If we look at a well log, we can see beds and we can see porosity that will be constrained to what we'll define as beds. If the porosity seems to develop across things that look like multiple beds, we might consider those vertical -- that would be vertical communication.

If we go through a portion of our log that's dense, no porosity, and then we encounter another porosity zone in the well, right there at the wellbore there's no vertical communication. At some distance from the wellbore, perhaps those two porosity zones merge together, perhaps they remain separated.

To the degree that those are separated by tight rock, I would say there's no communication between those zones. I think that's what we see when we look at the Monument-Tubb field with this very poorly segregated gas and oil production. Over time the hydrocarbons have not been able to sort themselves out because there's a very poor vertical communication between these multiple porosity zones.

Q. So taking that answer in combination with Exhibit Number 14, which discusses the height of the -- thickness of the producing interval --

A. Uh-huh.

Q. -- and comparing that with Exhibit Number 24-B, do you see more than 30 feet between these producing intervals in the Barber Number 12?

A. Excuse me, I'm still looking for 24-B.

Q. 24-B.

A. Which one was that? Oh, the two-well cross-section.

Q. The two-well cross-section.

A. Okay. Would you please -- Now, I'm with you. Would you restate the question?

Q. The question is, in Exhibit 14 we were told that there were 30 feet of thickness of production. In Exhibit 24-B, are we looking at more than 30 feet?

A. At what portion of that exhibit?

Q. Within the perforated intervals and the intervals that would be expected to contribute to production within this well. The highlighted area covers more than 30 feet on that exhibit.

A. That's correct, right. The top to bottom of the orange stripe?

Q. Uh-huh.

A. That's correct. When I apply the porosity cutoffs that I established to try to determine what rock contributes to production and what rock doesn't contribute, the vertical thickness of porosity in excess of those

cutoffs is equal to 30 feet. And that 30 feet is not meant to equate at all to the top and bottom of that orange bar.

Q. Okay, looking at the whole series of logs that were run on this, would you say that there is any production behind pipe that has not yet been perforated?

A. Yes.

Q. Okay. I was a little confused on Exhibit Number 28, and this exhibit you didn't have enough time to amend after you got the additional information; is that right?

A. That's correct.

Q. I was just wondering when that Barber Federal Number 1 was recompleted and if the thickness that you have listed here is 40 feet, does that correlate with the high-production wells that you showed in the three zones on one of the previous exhibits?

A. Does it correlate with the --

Q. The high production zones, areas, the --

A. -- you mean --

Q. -- Cooper and the --

A. -- the gas areas?

Q. -- Weir areas --

A. Oh, oh --

Q. -- yes.

A. -- okay. Exhibit 30 contains a copy of the mud log that I was able to make from Chevron's -- I think it

was -- no, one of the parties' prior exhibits in March of this year. My understanding of that well -- and I'm sure Conoco can correct any mistakes here -- that was a deepening attempt that drilled through the Tubb, logged it on the mud log. My understanding is the well encountered mechanical difficulties, open hole logs were not run, it was subsequently plugged back above the Tubb and a completion was made shallower. There's no Tubb test or production in that well, to my knowledge, no. Perhaps Conoco has some other information.

COMMISSIONER BAILEY: That's all I have.

CHAIRMAN WROTENBERY: Commissioner Lee?

EXAMINATION

BY COMMISSIONER LEE:

Q. Well, let's go through Exhibit 14. The initial bottomhole pressure, does Conoco agree with your bottomhole pressure?

A. My recollection from Conoco's exhibit submitted for this hearing is that their bottomhole pressure is different than the bottomhole pressure we show on Exhibit 14.

Excuse me, I'm saying initial. Is that what you asked? Initial bottomhole pressure?

Q. Yes.

A. Yes.

Q. Okay, so this agrees?

A. That's correct.

Q. The porosity, then they agree with your porosity?

A. The current exhibit for this hearing -- you'll see it shortly -- that I believe sets forth porosity on behalf of Conoco/Chevron, indicates a porosity that's not equal to ours.

Q. So how many percent difference?

CHAIRMAN WROTENBERY: We will be hearing from Chevron --

COMMISSIONER LEE: Yeah, but I would like to --

THE WITNESS: Yeah, I made a note of that, if you give me a second.

I wrote down -- Viewing Conoco's exhibit, yet to be introduced, for December, they indicated a porosity value of 6.6 percent that they utilized in their calculations.

Q. (By Commissioner Lee) Okay, the other one is -- Are you implying this reservoir has a gas cap?

A. No.

Q. No?

A. And let me qualify that.

In the extent, the classic sense that there exists a gas cap, the expansion of which provides reservoir pressure to produce underlying oil, I don't think that's

the case.

Q. So you see this -- the whole zone, there's no gas?

A. No. We can get into semantics, I think, and -- once again, petroleum engineering semantics. But if we view the Monument-Tubb field, we could -- and I've done this -- make a --

Q. Do they have gas?

A. There are gas wells that produce gas in the --

Q. Do they have --

A. -- Monument-Tubb.

Q. -- liquid?

A. They make small amounts of liquid in some --

Q. Are they in --

A. -- and --

Q. -- contact with each other?

A. On a geological basis?

Q. Yes.

A. I think we'd have to examine the pressure data of those wells to decide if they were in communication, if that's what you're implying.

Q. So you've got a zone, your liquid and your vapor is not in contact with each other? They have their own distinct properties, instead of a --

A. That's what I'm -- That's what I'm suggesting, is

that this reservoir is so complex that it just -- to me, in my brain, it is an accumulation of -- probably, like I said, in any couple of wells you might have communication; but overall there's -- almost every well may be in its own little fluid compartment.

You see a broad communication, you see increased GOR on structure, but it's --

Q. But your high perforation, we've got high GOR, right?

A. Not in all wells. Excuse me, this is -- It's difficult to talk about this reservoir in, let's just say, a classic sense of a homogeneous reservoir of a certain thickness.

Q. Did anybody take a sample of the fluid?

MR. TRAVIS: (Shakes head)

Q. (By Commissioner Lee) Very lousy operation.

Okay, then if you don't know, if you have a mix-up, then how can you determine the residue saturation?

A. The reservoir saturation?

Q. Residue saturation. Because your -- water also encroaching to your reservoir, right. There's no --

A. I don't think that's the case in this reservoir, I don't --

Q. The whole zone --

A. Uh-huh.

Q. -- is oil and gas and they --

A. Uh-huh.

Q. -- don't even talk to each other? And no water?

A. I found no evidence that there is what we'd think of as downdip water.

And I haven't gone to make a study that far downdip to even see if -- I didn't find any wet wells. In my mind, this is a stratigraphic trap with structural enhancement.

Q. All right, I don't --

A. I mean --

Q. -- know this reservoir either, so...

And how about -- This goes to Commissioner Jami's question -- how do you decide this 30 feet?

A. When we presented -- When I presented my isopach map -- and there's also in the exhibit that I didn't testify with, but Exhibit Number -- I believe it's 30 --

Q. All right, then --

A. -- but --

Q. -- another thing is --

A. -- I --

Q. -- I don't want to go into detail. How about the other side? Do they agree it's 30 feet?

A. No.

Q. So we are coming down with those basic

properties, and both sides doesn't even agree, right? So that's...

Do you really know who's right and who's wrong?

A. Mr. Lee, in my opinion I've studied enough of the geology of this reservoir that what I see in the subsurface, the implications about its internal architecture based on the production we see in Monument-Tubb, the correlation of the Barber 12 to the Monument-Tubb geology, which is very high confidence, that a limited drainage area such as Mr. Travis is calculating is very consistent with the geological reservoir attributes and the performance that we've seen in these rocks immediately to the east.

When you can drill a well on an 80-acre location 32 years after another gas well has produced over 6 BCF and still recover 1.8 BCF, then that original well is not effectively depleting that reservoir on a very large area. That's -- Basically, that is my main conclusion, that Mr. Travis's calculations of drainage are consistent and correlative to the geological description of this reservoir.

COMMISSIONER LEE: All right, thank you.

THE WITNESS: You're welcome.

CHAIRMAN WROTENBERY: Mr. Kellahin, anything further from Mr. Von Rhee?

MR. KELLAHIN: No, ma'am.

CHAIRMAN WROTENBERY: Okay, thank you very much for your testimony --

THE WITNESS: You're welcome.

CHAIRMAN WROTENBERY: -- Mr. Von Rhee.

Anything further?

MR. KELLAHIN: That concludes our presentation on direct?

CHAIRMAN WROTENBERY: Mr. Carr, call your first witness.

MR. CARR: May it please the Commission, at this time I call Tim Denny, our geological witness.

We have filed a number of exhibits, we've revised certain exhibits. We intend to, with Mr. Denny, go through Exhibits 1 through 5 and then Exhibits 11 and 12, and certain of those exhibits have been revised.

I do have additional copies of them if you need them.

CHAIRMAN WROTENBERY: You submitted the revised exhibits --

MR. CARR: Yes, we did.

CHAIRMAN WROTENBERY: -- to us previously?

MR. CARR: Yes, we did.

CHAIRMAN WROTENBERY: I think we've got them all, but we'll find that out, I guess, as we go.

TIM DENNY,

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

DIRECT EXAMINATION

BY MR. CARR:

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

A. Tim Denny.

Q. Mr. Denny, where do you reside?

A. Midland, Texas.

Q. By whom are you employed?

A. Chevron, USA.

Q. What is your position with Chevron USA?

A. I'm a geologist.

Q. Have you previously testified before the New Mexico Oil Conservation Commission?

A. I've testified at a motion hearing.

Q. At the time of that testimony, were your credentials accepted and made a matter of record?

A. Yes.

Q. I think it might be helpful, anyway, to review briefly for Dr. Lee and Ms. Bailey -- I think Ms. Wrotenbery was there -- could you review your education and background, please?

A. I have a bachelor and master's degree from the University of Nebraska, and I've worked for Chevron for 22

years.

Q. Your degree is in geology?

A. Yes, sir.

Q. And you've been employed by Chevron as a geologist?

A. That's right.

Q. Are you familiar with the Applications filed in these consolidated cases on behalf of Sapient?

A. Yes.

Q. Are you familiar with the lands in the area which is the subject of this Application?

A. Yes.

Q. Have you made a geological study of the area which is involved in this case?

A. Yes.

Q. Are you prepared to share the results of that work with the Oil Conservation Commission?

A. Yes.

MR. CARR: We tender Mr. Denny as an expert witness in petroleum geology.

MR. KELLAHIN: No objection.

CHAIRMAN WROTENBERY: We find that Mr. Denny is so qualified.

Q. (By Mr. Carr) Initially, would you summarize for the Commission what it is that Chevron and Conoco seek in

this case?

A. We seek an order denying Sapient of their Applications and require that the Commission continue with their ruling of the standard 160-acre proration unit at this location and that no retroactive adjustments be made.

Q. Would you refer to what has been marked for identification as Chevron/Conoco Exhibit Number 1, identify that and briefly explain to the Commission what it shows?

A. It's one of the original displays that was submitted back in November.

Q. Now, this exhibit was not revised in the materials filed last week; is that correct?

A. That's correct, that's correct.

Q. And since in the last couple of weeks we've made a couple of changes to this exhibit, they are reflected in the copies except the one on the easel; is that right?

A. That's correct.

Q. What is that change?

A. If you made a couple of corrections as far as gas symbols, if you see in the -- Can I point?

CHAIRMAN WROTENBERY: Please.

THE WITNESS: If you look here on your display, I think that was shown as an oil well.

Q. (By Mr. Carr) And you're pointing to the Barber well?

A. And this is the Barber Number 12, the Sapient Barber 12. So that's a gas well.

Q. And north of it?

A. And then we've also recompleted the Matthews Number 12 well, which is a Chevron well, which is located here, which is not on the map.

Q. Do you know the footage location in the Matthews 12?

A. It's 330 from the south and 990 from the east, Section 6.

Q. Those are the only changes in the exhibit?

A. I believe so.

Q. Can you identify the Chevron and Conoco acreage as depicted on this exhibit?

A. The Chevron 100-percent acreage is in the southeast quarter of Section 6. That's 100-percent fee acreage. That's highlighted in yellow. And the area in blue represents acreage that Chevron and Conoco both have an interest in, and that's a federal lease, and Chevron has 18.7 percent and Conoco has 37.4 percent of the acreage indicated in blue.

Q. The east half of the east half of the section, is that the Sapient tract we've been talking about?

A. Yes.

Q. Were you involved with the development of

Chevron's interest in this acreage?

A. Yes.

Q. Let's go to what has been marked as Exhibit Number 2, the chronology, and I would ask you to briefly review the information on that exhibit.

A. I think that's it, is the chronology. It's a word document.

We just wanted to show when the Sapient well first was recompleted, and they actually started the work, I think, in August. The well came on in September of 1999. And it was at an unorthodox location, it was 330 feet from the north line of Section 7, and the spacing for the Tubb should be 160 acres for a gas well. And the acreage indicated in blue there, there's a black outline which is a 160-acre proration, a standard 160-acre proration unit square.

And the acreage in the west half of the northeast quarter would be Chevron/Conoco acreage, which would be in that 160-acre proration unit.

Q. The Sapient well, the Bertha Barber Well Number 12, first produced in September, 1999?

A. That's right.

Q. In the year that followed that, prior to the filing of the Application to recomplete the Matthews 12, could you review for us what Chevron did in terms of its

efforts to develop the offsetting property there to the north and the southeast of 6?

A. In Section 6, in the northeast quarter, we had identified that Sapient had a producing well, and so we evaluated our lease and our wells to see if we could recomplete one of our wells into the Tubb formation. And we decided to try the Matthews Number 6 well, which is a little bit farther north if you look on your Exhibit Number 1. It's a little farther north. I forget the exact footages, but it's a standard location in the southeast quarter of 6. And we picked that well because it had casing all the way through the Tubb and we could just go in and perforate it.

We logged that well in November of 1999, and then we actually started doing the work in July through -- or in March and July of 2000, trying to get the well to produce out of the Tubb, and we were unsuccessful in getting production out of the Tubb.

Q. And it was after you were unsuccessful in that effort that you moved to the Matthews Number 12?

A. That's correct.

Q. And when did you submit your Application for permit to drill for that well?

A. We submitted that in early October, I think it was the 11th of October, and because -- we did that because

we were unsuccessful in the Matthews Number 6 well. And Sapient objected to that, and the hearing was set for January 25th of 2001.

Q. And what happened when that matter came on for hearing?

A. Two days before the hearing, Sapient withdrew its objection. And so by virtue of the objection they were able to produce the well for an additional three months.

Q. While you were trying to get your permit approved?

A. That's correct.

Q. And the actual applications, the original hearing on applications for spacing changes for the Barber 12, the Division hearing that's under appeal here today, that was held on March the 1st, 2000. Did Chevron at that time request that the Barber well be shut in?

A. Yes.

Q. And had you requested that of the Division prior to that time?

A. I believe so.

Q. And what response was there to that request?

A. There was no order issued to shut in the well.

Q. And when was the order actually entered in the Division case which directed that the well be shut in?

A. Not until October 17th of 2001.

Q. That was the actual shut-in order following the hearing on --

A. Actually, the order was on September 13th, I'm sorry.

Q. When was the well shut in?

A. And the well was not actually shut in till October 17th. So it's been, you know, over two years that the well has produced from when it first started in September of 1999 until October of 2001.

Q. Let's go to the geological portion of the case. Since the November hearing date could you identify for the Commission what new information you have acquired concerning this reservoir?

A. Well, we've recompleted the Matthews Number 12 well, as I indicated on the map up there, in the southeast quarter of Section 6, 330 off the south lease line. And we've obtained pressure data and we've logged the well, and we have also obtained sidewall core data.

Q. And have you revised certain exhibits to reflect this new information?

A. Yes.

Q. Let's go to what has been marked for identification as Chevron/Conoco Number 4. This is the structure map, and the exhibit label says "(Revised)". And we're going out of order, we're going to go 4 and then come

back to the cross-section which is Exhibit 3.

MR. TRAVIS: Bill, do you have any maps for me?

MR. CARR: I guess we probably do.

THE WITNESS: Well, this is a --

CHAIRMAN WROTENBERY: Do you need one?

THE WITNESS: I'm sorry.

CHAIRMAN WROTENBERY: Do you need one?

MR. CARR: No, I'll be fine.

CHAIRMAN WROTENBERY: You'll be fine.

MR. KELLAHIN: Works better without the facts.

MR. CARR: I have looked at these for so many months --

CHAIRMAN WROTENBERY: Okay.

MR. CARR: -- that I'm all right.

CHAIRMAN WROTENBERY: Okay.

Q. (By Mr. Carr) Would you first identify what is Chevron/Conoco Exhibit Number 4 and then review the information on that for the Commission?

A. This is a structure map on top of the Tubb formation, and I might -- This is actually a map on top of the Tubb, it's not some interval down lower in the section as Sapient has done. And the reason for doing that is just, you know, there's a lot of data on top of the Tubb and -- various PI sources and so forth, and it's easy to make regional maps if you just pick a marker that's been

used by a lot of people. So that's what this map was based on, the top of the Tubb.

And what you see here is -- The contour interval on this map is 25 feet. And if you look down here in Section 7, you'll see a little box. That's a 160-acre proration unit, a standard 160-acre unit.

The Sapient Number 12 you see in the northeast quarter of 7, and then you see right directly north of that and a little bit to the west is the Chevron Matthews Number 12 well, in the southeast quarter of Section 6.

And the gas-oil contact that I've shown here is based on the lowest perforations in the Sapient Barber Number 12. So we know they're making all gas, or nearly all gas, out of that well. And so we just said, Well, we know there's oil-free production down to that point, so we just said that's as low as we know the gas goes at this point. And that's what this red line is showing.

And this has also been adjusted. I just tried to get the reservoir in relation to the top of the Tubb formation, so I just made an adjustment based on the top perf in the Sapient and the top of the Tubb and adjusted it up 123 feet, so the contact fits with the structure map.

And also noted on -- There's a purple line here, and that is the line of cross-section that I'll talk about next. And you might note that by several of these wells on

that line of cross-section there's a GOR that's noted there, and that's the cumulative GOR. You can see the Sapient is very high, over a million.

And if you go to the wells on the upper part of the cross-section, on the right-hand side of the cross-section, you can see there's GORs of around 5000 and 2500 and 4500. And then off to the right there's 1400 and 1800. So you can see that clearly there's a big difference in the GOR, cumulative GOR.

Very little has changed on this map from the original mapping. We added the Matthews 12 location, and we didn't even have to adjust the contours. It fit right into the contour maps that we originally made.

And what you can see on this overall picture is, you can see there's a structural high going from northwest to southeast. And I think that's consistent with what Sapient had on their regional map in this area, the structural high in this orientation.

Q. All right, Mr. Denny, let's go to the cross-section, and we'll be looking at the cross-section that is marked "Exhibit 3 (Revised)".

A. Sorry this is so long. I should have tried to shrink it up a little bit, I guess, but...

Q. All right, let's identify this exhibit. First explain how you have revised it from the one filed a month

ago, and then review the information for the Commission.

A. Okay, this is a structural cross-section, as I've indicated on the structure map, the purple line. And the left-hand side of the cross-section, the well numbered Number 1 is the lower left cross-section on the map -- or well on the map, which is the Conoco Federal Barber Number 1 that was referred to earlier that just has a mud log in it. And then you work your way to the right of this cross-section, and that's the upper right on the map.

And what I've added on this cross-section versus the previous cross-section is just the Gulf -- the Matthews Number 12 well, which is the number three well on the cross-section.

And if you just look at the blue line here on the cross-section, that's the top of the Tubb marker. And you can see the Sapient and the Matthews wells are both structurally high to the other wells on the cross-section.

And the other thing I wanted to point out is, in the depth track you can see some red boxes. That's the perforated interval in these wells. And if you'll look in the Sapient Barber Number well [*sic*], we just put the gas -- lowest known gas contact, which is a red line, put that at the base of the perforations in the Sapient Barber 12. And we just carried that across.

And you can see if you look at this Marathon 18-Y

and the 16 and the 17, all those wells have some perforations that -- the 18-Y and 16-Y both have perforations slightly above that red line and some below that line. So we think that's fairly close to where there's a gas-oil contact, because the Marathon wells are producing oil and some gas, and the Sapient well is producing all gas.

Q. All right, let's go to the isopach. The isopach is --

A. Oh, one thing I wanted -- While we have the structural cross-section up, I've isopached in this purple line here, this TB22, I've isopached that down to the TB32, which is its ground line. So I tried to pick the interval that's easy to correlate in the Sapient Barber well, and it covers the interval where the perforations are, and that's the isopach map that we'll look at next.

Q. And that is Exhibit 5 (Revised).

A. Okay, this is Exhibit 5; is that correct?

Q. Yes, sir.

A. Okay, Exhibit 5 is the isopach of the Tubb section that I've just identified, it's the interval from the TB22 down to the TB32 on the cross-section. And this is basically the same area that I mapped on the structure map. And the contour interval on this map is five foot. And again, the acreage is shown as we've shown on Exhibit

1, Chevron in blue, and Sapient's in green, and the Conoco/Chevron acreage that's joint is in blue.

And this map is -- As you can see, the overall trend of this is, you have kind of a northwest-southeast trend of the isopach porosity. And the numbers here, if you look at the big blue numbers, that's the thickness values that I used to calculate this isopach map. And like if you look at the Sapient 12 well, I have "27cg". That "cg" means there's a corrected gamma ray. And so wherever you see "cg", that means I had a corrected gamma ray and probably had a modern porosity log, which had a neutron density or something like that in the well.

And also there's some wells that have "NL"; that means no log. And some other wells where I have like "gn"; that's a gamma-ray neutron log, an old deflection log. So I tried to use whatever data was available to make this map.

And as you can see here, I have the Chevron Barber 12 well in the southeast quarter of 6 with 29 feet, and the Sapient Barber well -- the Matthews well, excuse me, the Chevron Matthews well in Section -- southeast quarter of 6, Number 12. That's 29 feet. And the Sapient Number 12 well, that's 27 feet. So they're somewhat similar in net feet of pay.

Q. What porosity cutoff were you using?

A. This map was using -- Wherever I had modern logs, you know, I obviously used those because I think they're the best source of log porosity. And I used a crossplot porosity of 4 percent, and I used a sonic cutoff on a couple wells where I had sonic logs at 52 microseconds per foot. And I used a gamma-ray cutoff of 30 API units. So everything that was less than 30 API units was what I used. And if I didn't have a corrected gamma-ray, I used whatever was less than 50 API units.

Q. How does this mapping compare with the Sapient mapping, the isopach, Sapient Exhibit 28?

A. Well, the overall main difference is, we believe there's more of a northwest-southeast trend to the isopach thickness, which, if you look at this map there's a lot of data on it, a lot of wells we've tried to incorporate, and it gives us that trend.

And we feel that trend is a trend that seems reasonable, related to the depositional environment that we have here. We have a shallow shelf, we have beds that -- the shelf edges out here to the southwest, and we think that the facies tracks ought to be more or less parallelling the shelf edge, and therefore the porosity should be similar to the facies, because that's usually how porosity is developed in different facies.

And that makes sense to have those porosity

values somewhat parallel to shelf edges. And these data points suggest that it fits with that orientation, and we feel like that's a reasonable interpretation on how to correlate these isopach values.

The other difference is, we don't have a value down here for that well that's in question on the -- not in question, but a well that Conoco drilled, that Number 1 in Section 7, where I think Sapient had -- one of the main differences, they had a value of 40 feet there, and we feel like that's a data point that we didn't care to use. We used it on structure interpretation, but we think on a qualitative basis it's okay to use something like that to pick a structural top.

But on a quantitative basis, trying to come up with a feet of pay based on rate of penetration, we feel like that's a stretch, because you've got different bit types, different weights on bit when a well is drilled, we have different mud weights, a lot of variables that affect rate of penetration. And to try to use that and say there's some sort of relationship to porosity and what kind of porosity, how big a -- or what value of porosity, is very difficult to do, and we don't think that's a reliable method in calculating porosity. So we have no value for that Conoco well in Section 7.

Q. And that's because you only have the mud log?

A. That's correct, there's no logs, just a mud log.

Q. And as a result of that, you have mapped the reservoir parallel to the edge shelf, correct?

A. Well, in some fashion similar to that.

Q. And Sapient is more perpendicular to it?

A. Yes, they -- because of that, they have kind of a more north-south trend to their isopach map, and we have more of a northwest-southeast trend.

Q. Mr. Denny, I would like you to go to a new exhibit, what has been marked as Chevron/Conoco Exhibit Number 11. Could you explain to us what this exhibit is?

A. It's this one.

What this shows is, as I mentioned earlier, when we deepened the Matthews Number 12 well, the Chevron Matthews Number 12 well, we were able to log it and get some modern porosity logs, and we were also able to get some pressure data and also some sidewall core data.

And this display -- I start on the left-hand side -- this is -- the gamma-ray is in the left-hand track, and that's highlighted anything that's -- this is a corrected gamma-ray curve, and anything less than 30 API units is shaded in green, all in green.

And then as you move to the depth track, the red indicates the perforations that were done in the Matthews 12 well.

The blue line represents the crossplot porosity that was obtained when we logged the well.

And the red dots are the sidewall core helium porosity values that were calculated by Core Lab, and those are overlain on the same scale to show you the very good correlation between the sidewall core and the neutron density crossplot.

And we think this is a real key to -- this is a real key, this sidewall core versus the neutron density crossplot, calculating an accurate porosity value for the Matthews 12 well and the Sapient Number 12. Those are the two key wells that we're talking about here today, and no matter what you do, you know, around this area, this is the two that we're talking about. And these core values substantiate that the neutron density crossplot is a good curve to use to get accurate porosity values.

Q. Now, when you are asked to determine porosity for the Matthews well or the Barber well, what do you use? Do you use the neutron density crossplot information?

A. Right.

Q. And why do you do that?

A. Well, we chose to use the neutron density crossplot because it's an industry standard method of calculating porosity, because if you just take one tool by itself, either the density or the neutron, you probably

aren't going to get an accurate porosity value. So the industry standard or common practice or common method of determining porosity is to do a neutron density crossplot, which most of these logging companies provide when you actually log the well.

And reason you do that is because it takes out lithology effects for the neutron and the density, it takes out effects for gas and that kind of stuff. So it takes out -- it normalizes the effects of the density and the neutron on gas, and it also calculates the correct porosity or a close approximation to what the true porosity should be.

Q. When you use these curves to calculate porosity, aren't you trying just to determine what the rock is like, what the porosity is in the reservoir?

A. Yes.

Q. And here with the sidewall cores, do you actually have the rock from the reservoir?

A. That's right.

Q. And those samples of porosity, you can then take that rock and you can determine what the porosity is in that sample?

A. Yes.

Q. And you have plotted those on this log; is that correct?

A. That's right.

Q. And those are the red dots shown on this log?

A. That's right.

Q. And the correlation that you can see between the red dots and the curve, do they confirm the accuracy of the curve to you?

A. Yes, I think they give a very good fit.

Q. Now, you don't agree with Sapient in terms of the porosity numbers; is that correct?

A. It appears that they have a higher porosity value for the Sapient Barber Number 12 than we do.

Q. But you've been able to confirm your curve with actual rock property from the reservoir itself?

A. That's correct.

Q. Let's go to Exhibit Number 12. Would you identify that, please?

A. Okay, Exhibit Number 12 is a -- I tried to show the two wells in question here, the Sapient Barber Number 12 on the left and the Matthews 12 well on the right. And again, the gamma-ray, corrected gamma-ray, is highlighted, everything less than 30 API is highlighted in olive green, the perfs are in red. The blue shaded is the crossplot porosity that's greater than 4 percent, and the yellow is porosity that's calculated from the PE curve using PE and bulk density.

And as you can see, we've used the crossplot porosity, and if you look at the porosity calculated from the PE bulk density crossplot -- or PE -- the porosity calculated from the PE and bulk density, you see that it's significantly higher than the neutron density crossplot. And because we have sidewall core data that matches the neutron density crossplot, we think that's a more accurate method of calculating.

Trying to use the PE curve, incorporating the PE curve into some kind of measurement to calculate a different matrix density, we think, is a method that's not a standard method of -- way of calculating porosity. And PE curve is affected by -- You have to know what two lithologies you're dealing with. And I think the only way you really know if you have the correct lithologies is if you somehow compare it to another porosity measurement, which is like the neutron density. So you don't really know if you have the correct lithologies to predict what your porosity is.

And also, when we took the sidewall core data, we discovered that we had some other minerals in this section that are very -- have big effects on PE. There are PE values that are off-scale on the charts that Schlumberger has. There's a mineral called anchorite that has a PE of 9, and dolomite has a PE of about 3.1, and limestone has a

PE of about 5, and sands are less than 3. So here's anchorite out here at 9. And there's also a little bit of pyrite in this section, and that as a PE of 16.

So when you start throwing in these other minerals that have been identified through X-ray diffraction, it adds even more question to using any kind of value related to PE.

Q. When you had these other minerals present, do you believe you can get an accurate read on porosity by using the PE curve alone?

A. No, I think it makes it very difficult to get an accurate porosity measurement using PE.

Q. If we look at Exhibit Number 12, the two logs, is it a fair characterization that they look like the logs are virtually mirror images of each other, slight variations?

A. Yeah, that's a good question, that if you look here at the gamma-ray response and also at the porosity curves, you see there's a pretty good correlation between the two wells. They seem to be easy to correlate and have very similar characteristics.

And as we've calculated at the bottom of this plot, if you'll look down at the very bottom, we have gross and net feet, and you can see the net feet we calculated for the Sapient well. That's about 26 1/2. And for the Matthews well it's about 29 feet. And the average

porosity, you can see here, the Sapient is 6.7 and the Matthews Number 12 is about 6.5.

So they have similar porosity calculations, similar net feet, and we've used the same data, the same cutoff.

And I might mention, there's been some question earlier about the different porosities that have been used in the past in other hearings. Some of the original data, Sapient did a very cursory look, you know, the porosity value that was used at different times were -- quick look, you know, what you think the porosity might be, just to get a feel for the area of drainage.

So not until this analysis where we did just what Sapient did, we digitized the Sapient well, and then on the Matthews well we had digital data when we logged the data. So we digitized the Sapient well, and we did a rigorous analysis of what the porosity is, and we used cutoffs that -- I don't think you've heard Sapient mention any kind of a gamma-ray cutoff.

So if you start incorporating gamma-ray cutoffs, which we think tie back to effective porosity, that's what these green flags are. The green flags on the right-hand side of the track show what we -- what meets the gamma-ray cutoff and what meets the neutron density crossplot cutoff. So it had to have both those criteria to meet our cutoff on

net feet and average porosity.

Q. If we look at the green area on these logs, that's the neutron density crossplot, and that's what you used; is that right?

A. The green area highlights --

Q. I mean, I'm sorry, the blue area --

A. Yes.

Q. -- is the neutron density crossplot, and that's what you used to estimate porosity?

A. Yeah, everything that's greater than 4 percent is highlighted.

Q. And the yellow is what you get if you use the PE curve?

A. That's correct.

Q. And the difference is the difference that you have between how you've done it and how Sapient has done it on the Barber well; is that right?

A. Right -- Well, I don't know how they've done it for sure, but --

Q. But if you use the PE curve, that's the difference; is that right?

A. Yes.

Q. And Dr. Lee asked, how do you know which is right? And how do you know which is right, Mr. Denny?

A. Well, we just -- Based on the sidewall core data,

we think that that very closely matches the neutron density crossplot, and that's our preferred choice for these wells in question.

Q. And this porosity information is then what is used in the engineering data, which will be presented later?

A. That's correct.

Q. What conclusions have you reached from your geologic study?

A. Well, our conclusions are that structurally we have a high area that's trending to the northwest-southeast.

We have an isopach thickness that trends similar to that structural trend, and we've -- the isopach is based on data that we've used, industry-standard methods for calculating porosity to use on this map. This map shows -- isopach shows a consistent regional trend of isopach values.

And the sidewall data that we acquired in the Matthews 12 well matches our crossplot porosity for neutron density.

And also, I've mentioned that we have about 29 feet of pay in the Matthews 12, and the Sapient we have about 27 feet. They both have close to around 6-1/2-percent porosity.

We've used gamma-ray cutoffs on our wells to evaluate pay, and we think that we -- we believe that we've used an optimistic cutoff of 4 percent. You know, if you used a higher porosity cutoff with these gamma-ray cutoffs and so forth that we're using, as you move the porosity value higher you eliminate pay. So we think we've been optimistic in calculating a large number of net-pay feet. And...

Q. All right, Mr. Denny, were Chevron Exhibits 1 through 5, 11 and 12 prepared by you or compiled at your direction?

A. Yes.

MR. CARR: At this time we'd move the admission into evidence of Chevron/Conoco Exhibits 1 through 5, 11 and 12.

CHAIRMAN WROTENBERY: Any objections?

MR. KELLAHIN: No objection.

CHAIRMAN WROTENBERY: Exhibits 1, 2, 3 (Revised), 4 (Revised), 5 (Revised), 11 and 12 are admitted into evidence. Did I get that right?

MR. CARR: Yes, you did, and that concludes my direct examination.

CHAIRMAN WROTENBERY: Okay, thank you.

Mr. Kellahin?

MR. KELLAHIN: Thank you.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Denny, you testified in the March hearing before Examiner Stogner in this case?

A. Yes.

Q. And during your testimony, you advised us that you were the geologist responsible for the Tubb area?

A. Yes.

Q. And that responsibility preceded September of 1999?

A. That was one of many areas that I covered.

Q. When other operators in the Tubb area drill and complete and start producing wells, would it be an issue or a matter that would come to your attention?

A. I try to keep abreast of all the wells in my area, which included all of Lea County and a large portion of -- or all of Eddy County and a large portion of Lea County. So I cover a big area.

Q. So when Cross Timbers recompletes the Barber 12 well into the Tubb in September of 1999, directly south of property owned by Chevron, that would be information that would come to your attention?

A. Yes, I did pick it up on PI.

Q. Having that knowledge in September of 1999, it was not until July of the year 2000 that Chevron decided to

recomplete the Matthews 6 well, correct?

A. In November of 1999 we went out -- The sapient well in question was completed in September of 1999. In October of 1999 we went out and logged the Matthews Number 6 well because, as I mentioned earlier, we had casing in that well, we thought it would be a well that we could easily re-enter, it wouldn't cost us a lot of money, and we could maybe make a well in the Tubb.

So in November of 1999 we went out and logged that well. And March of 2000 we started the work on that well, and we actually completed trying to complete that well, finished the work in July of 2000.

Q. All right. So from September of 1999 to July of the year 2000, during that period of time Cross Timbers was producing the Barber 12 well, correct?

A. That's right.

Q. And Chevron's response to that well in terms of having a competing well in the Tubb was entirely within Chevron's control, correct?

A. As I said, we picked the Number 6 for economic reasons.

Q. All right. When you picked the Number 6 well, the Number 6 well is located 1650 feet north of the common boundary between what is now the Sapient well and the Chevron property, correct?

A. I'm not sure of exact footages, but it's farther north, that's correct.

Q. All right. Of all of the wells in the population you had in the southeast quarter of 6, you chose the Number 6 well, or Chevron chose the Number 6 well, for economic reasons? It was cheaper to re-enter that and try to recomplete it in the Tubb, correct?

A. That's correct.

Q. All right. Was the Number 12, the Matthews 12 wellbore, available to you at that time?

A. The Matthews 12 well produced out of the Grayburg-San Andres, so it was a producing gas well. And that was another reason for not trying to convert that well, or to try to take that well and deepen it, we had to deepen it 1200 or 1300 feet down to the Tubb, and it was also a producing gas well, which we didn't really want to knock over. So we chose to do the Matthews 6 because the 12 is still producing out of another formation. And the Matthews 12 is going to cost us a lot more money to deepen and to try to recomplete.

Q. Those were business decisions that Chevron made entirely within their control?

A. Yes.

Q. Then in July of the year 2000, you attempt to produce the Matthews 6 well, the well farther north, and

you discover that the formation, the Tubb formation, is too tight to produce, correct?

A. We were not able to successfully complete that well. We think we had mechanical problems when we frac'd the well.

Q. Okay. Do you recall Mr. Lloyd Trautman's letter to the Division dated November 7th of the year 2000 in which Mr. Trautman discussed Chevron's efforts on the Number 6 well?

A. I don't remember dates or anything, I just know that there was -- he was asked to respond, and he made some response.

Q. All right, sir, let me show you that exhibit. Who is or was Mr. Trautman, Mr. Denny?

A. Lloyd Trautman is an engineer that works for Chevron, and at the time he was working in New Mexico. He's no longer in this group, he's working in a different part of Chevron.

Q. All right. On October 11th of the year 2000, Chevron files an administrative application for the Matthews 12 well, seeking to have it approved at a location that's 330 from the common line, correct?

A. I believe that's correct, yes.

Q. And Mr. Trautman's letter is in response to Mr. Stogner's request for additional information on the wells

in the southeast quarter of Section 6, correct?

A. That's correct.

Q. If you'll look at the last sentence of the second paragraph on the first page, Mr. Trautman is representing to the Division --

A. What paragraph are you on again?

Q. I'm sorry, it's the second paragraph.

A. All right.

Q. If you start reading about halfway down it says, "At this time we decided to recomplete the #6 well..." located 990 from the east, 1650 from the south of 6. Permits were obtained, the work was completed in July, and the Tubb zone was tight.

It goes on and talks about proper treatment not being possible, "Production testing resulted in no fluid entry."

Is there anything in this letter that indicates the Number 6 well failed for mechanical reasons?

A. Well, when I said mechanical I just mean the way we designed our frac, we don't know if that was an effective way to try to frac the well, and when I said mechanical I meant from a method of how we did the frac job. We weren't able to get any sand in the formation. We screened out very quickly, so we weren't able to frac the well, and we weren't able to establish production.

Q. All right. In response -- In reply, then, Mr. Trautman's filed the request of Mr. Stogner. Then at a prehearing conference in this case on January 24th, Mr. Stogner issued an administrative order approving the Chevron location for the Matthews 12 well, did he not?

A. Yes, I believe that's correct.

Q. Administrative Order NSL-3752-A. So January 24th, you've got the approval, now, to re-enter the Matthews 12 and attempt to complete in the Tubb, right?

A. That's correct.

Q. All right. At the March 1st hearing, Examiner Stogner discovers that Chevron had failed to notify all the appropriate parties to the south of us of their application for the Matthew 12, correct?

A. Conoco had not been notified.

Q. Yes, sir. And so he suspended your administrative approval, didn't he?

A. That's right, he put a stay on it --

Q. All right.

A. -- which has never left it until September. We had --

Q. He reinstated your approval on August 9th, the way I have it here, Mr. Denny.

A. Okay.

Q. All right. So on August 9th, Mr. Stogner has

satisfied himself that you've complied with the notice requirements, he reinstates the approval to re-enter and attempt to produce the Matthew 12, correct?

A. I'm not sure exact dates, but if that's what you have there I believe you.

Q. When did Chevron commence its activity to re-enter the Matthews 12?

A. We started work on that -- I can't remember exactly what the date on that is, but we started work on that shortly after that. We were able to pick up a rig, and it's just taken us a long time to get all the mechanical. We had a lot of open perfs, we had a lot of bridge plugs we had to drill out. It took a long time to get the actual work accomplished in that well. And then once we got that done, then we had to move in a drilling rig that we could actually deepen the well.

So between move-rigging -- doing the mechanical work to get the bridge plugs drilled out and the cement squeezes done -- I think we had five sets of perfs we had to squeeze -- it took us a lot of work. But we started on it -- I don't know what the date was, we started soon after that.

Q. Okay. You're not suggesting, are you, sir, that from the date of first production in the Barber 12 well, Cross Timbers, until Sapient filed an objection to your

administrative application in October, that any of that time period is Sapient's responsibility?

A. Would you repeat the question?

Q. Yes, sir. From the time Cross Timbers started producing the Barber 12 well --

A. Right.

Q. -- all the way through, that's September of 1999, until late October of the year 2000, during that entire period of time, the reason that Chevron did not attempt to complete an offsetting well was entirely within your control?

A. No, that's not true. We did try to do the Matthews 12, and in July of 2000 we were unsuccessful with that. And then we applied for a nonstandard location -- or we tried the Number 6, were unsuccessful in that. Then we applied for the permit for a nonstandard location, and that was -- you know, that's when Sapient rejected that. And then we've had the stay on the well, and --

Q. That occurred in October of the year 2000, the objection from Sapient?

A. That's correct, and we --

Q. In January --

A. -- didn't go to hearing until January.

Q. In January the objection is withdrawn --

A. That's --

Q. -- your well is approved?

A. That's right.

Q. And from January, then, until --

A. It was the end of January --

Q. Yes, sir.

A. -- until the 1st of March, then the well had a stay put on it. And the time frame there, that one month, we just could not pick up a rig, whereas at that time there was a lot of activity in the oilfield and we weren't able to get a drilling rig.

Q. Well, my question, Mr. Denny, is that the reason the permit was pulled or stayed by Mr. Stogner had nothing to do with Sapient, did it? It had to do with Chevron complying with the notice requirements?

A. As far as that stay, that's correct.

Q. Okay. You talked about frac'ing the Number 6.

A. Yes.

Q. Did you frac the Matthews 12?

A. We have not yet.

Q. Do you intend to do that?

A. I'm not the engineer, but my guess would be probably so.

Q. That's the common practice in the Tubb, to --

A. Right.

Q. -- fracture these wells, isn't it?

A. The Sapient well was producing about 600 MCF until they frac'd that well. At that time the rates went up to 1.4 million a day. So I would guess that we would want to frac our well too.

Q. Let me direct your attention to the structure map, your structure map. It's Exhibit Number 4 (Revised). For purposes of this hearing, Mr. Denny, does it really matter to anybody about where this gas-oil contact is?

A. What we're just trying to show is where the lowest known gas is in the Sapient well.

Q. Mr. Von Rhee testified that there's a substantial footage overlap between the lowest gas and the highest oil, true?

A. In other wells there is some overlap in the perforated interval on the Matador -- or Marathon wells.

Q. What is the purpose of the pink shading on the exhibit? What are you implying here?

A. It's just -- We know where the gas -- the lowest known gas is in the Sapient well, and if you just carry that out on a contour basis, that's where you would expect to find gas.

Q. Are you trying to draw any kind of geologic connection between the Marathon oil wells in the west half of 5 and the Sapient Barber 12 well?

A. Well, remember on that cross-section I showed the

gas contact, and there were perforations below that -- there were perforations below the red line on the cross-section in these Marathon wells. And there's also a few perforations above that red line.

So we're just trying to show that it's conceivable that they were producing -- they were close to where that gas contact might be.

Q. You're not intending to conclude that we have a gas cap with the Sapient well upstructure to Marathon's downstructure oil wells, are you?

A. We were just trying to identify in the Sapient well where the lowest known contact might be for gas.

Q. Then you're not intending to have us conclude from your testimony that we should be concerned about a gas-cap reservoir?

A. Well, we know we're producing gas out of the Sapient well, we know we're producing gas out of the Barber Number 12 well, so...

Q. Isn't it critical to reservoir management by the regulators to have experts such as you tell them if they have a concern about a gas cap?

A. Well, you know, I don't have any more data than you do over on those Marathon wells, I don't have any pressure data, so I really can't say what the relationships are.

Q. Okay. At this point Chevron is not suggesting that the Division or the Commission should initiate action to declare this an associated oil and gas pool subject to those rules?

A. I don't if I'm -- I don't think I'm the right person to ask that to.

Q. You don't know about the associated rules?

A. No, I'm not an expert on that.

Q. Let's look in the southwest southwest of 5.

A. Southwest southwest of 5.

Q. Yes, sir.

A. Okay.

Q. There's an open area with no well.

A. Yes.

Q. Am I correct in understanding that Section 5 is in the oil pool, correct?

A. That would be my guess.

Q. All right. Did you see that on Mr. Travis's exhibits earlier today, where he outlined the oil pool?

A. No, I didn't.

Q. All right.

A. I didn't look that close.

Q. Okay. Are you aware that the Marathon oil wells in the southwest quarter of 5 are oriented to a spacing unit where the north half of the southwest quarter of 5 is

dedicated to two of Marathon's wells in the Tubb formation?

A. Yes.

Q. You knew that?

A. Yes.

Q. That leaves the south half of the southwest of 5 open, doesn't it?

A. That's correct.

Q. That is in the oil pool, Mr. Denny?

A. That's correct.

Q. Are you aware that Chevron has signed a waiver so that Amerada Hess could place a Tubb well 330 feet out of the west and south corner of Section 5?

A. Yeah, they have -- Amerada Hess has 40 acres in the southwest of the southwest of 5 and, you know, with the Monument-Tubb rules, which is what these Marathon wells are, these three, the 16, 17 and 18, those wells are in the Monument-Tubb. They're 80-acre spacing. You can be 330 off the line, and that's what Amerada Hess has the right to do, to drill a well 330 off the lease line.

Q. When we look at the structure map and look at your isopach, you show the southwest quarter of 5, the southeast of 6, the northeast of 7, to be within the same Tubb accumulation, don't you?

A. Would you state that again, please?

Q. Yes, sir. When you look at your structure map

and your isopach and take them together, you can see that the southwest of 5, the southeast of 6, and the northeast of 7, are all in the same Tubb accumulation?

A. All this is trying to represent is just the lowest known gas in the Sapient well, and the other wells are perf'd mostly below that. They're downstructure, and they're mostly below that lowest known -- most of the perforations are below that lowest known gas contact.

Q. I didn't make myself clear, Mr. Denny, I apologize. If Amerada Hess takes advantage of the waiver and drills the well 330 out of the southwest corner, they're going to be competing in the same Tubb interval with Sapient and with Chevron, correct?

A. Well, if you look at that 2700-foot contour on that structure map, you'll see that goes right through those Marathon wells that we're talking about. And you can see that the wells right there, the 18 Y and 16, have GORs of 5000 and 2500. So those wells are not gas wells. And if you follow that 2700-foot contour around, you know, the Amerada Hess location should be similar structurally to the Marathon wells, and therefore they should produce similar GORs. So I don't think they're going to be a gas well, they're going to be mostly oil.

Q. Do you think there would be continuous reservoir continuity between the Marathon oil wells, the Amerada Hess

location and the Chevron and Sapient gas wells?

A. In a general sense you can correlate all that interval and there's not significant differences. But the best correlation is between the Barber well and the Matthews well. There's a good correlation there.

As you move away from there, I can't predict what that well, the Amerada Hess, is going to have. I'm not -- You can always have surprises, I guess.

Q. Is this reservoir so compartmentalized and discontinuous that you don't have to worry about the Amerada Hess location?

A. No, I wouldn't say that's the case. I think you can correlate these intervals fairly easily, but, you know, as in any reservoir, your porosity can change in value, you know, as you move away from a well or get closer to another well. Not everything is just a continuous sponge and continuous all over the earth. So you can have changes in porosity, but as far as being real discontinuous and disconnected, I don't believe that's necessarily the case.

Q. If we're adopting rules for the exploration and production of hydrocarbons in the Tubb, wouldn't it make sense to have the rules the same for the southwest quarter of 5 as they are for the northeast of 7 and the southeast of 6?

A. Well, I'm not the rule maker. I don't profess to

know how to make the rules, that's not my job.

Q. Your job would be to look at the geology?

A. My job is to try to look at the geology and make maps such as I've done, structure maps and isopach maps.

Q. And geologically looking at structure, you can't separate out the southwest quarter of 5 from portions of 6 and 7; you've drawn it as the same structural feature, haven't you?

A. Yes.

Q. Okay. In the isopach you've shown it as a continuation of the same accumulation of hydrocarbons, haven't you?

A. Yeah, there's not enough data to try to start separating it.

Q. All right.

A. These maps are made to give general trends, to get general trends and general thickness values for calculating drainage radiuses.

Q. Mr. Denny, you saw Mr. Von Rhee's presentation this morning, did you not, sir?

A. Yes, sir.

Q. Have you made a similar study of the Tubb field?

A. In what sense?

Q. In the sense that he did, that he looked at the entire Monument-Tubb Oil Pool and its relationship to the

Sapient well?

A. I have not done that.

Q. On the isopach, is there some way -- Let's go to the structure map. On the structure map you've got a copy of the Sapient Barber 12 well on your cross-section? You do, don't you? Yeah, would you pull out your cross-section for me, Mr. Denny? I think on your cross-section you're going to have the Barber 12 well as the second well.

A. That's correct.

Q. All right. I want you to show me on the Barber 12 log where the top of the Tubb interval is that you're isopaching when we look at your Exhibit Number 5 revised.

A. The top of the isopach is that purple interval, TB22.

Q. Where's the bottom of the Tubb isopached interval, using the same log?

A. It's that kind of a yellow-colored line, TB32.

Q. All right, that's the interval, then, you're mapping on Exhibit Number 5 revised?

A. Right.

Q. Okay. Is there any difference between the interval that you have isopached in the Tubb and the interval Mr. Von Rhee isopached in the Tubb?

A. I'm not exactly clear where he isopached, but I think we're pretty close to the same section --

Q. All right.

A. -- from what I can understand where he put his tops in.

Q. So we can't resolve the difference between you based upon the fact one of you has picked a different top or bottom from the other?

A. Well, if he started where I did, they should be the same section.

Q. Go with me to your Exhibit Number 11, Mr. Denny.

A. Sorry, I don't really know what numbers they are.

Q. Well, it's the one-well digitized log.

A. Okay.

Q. It's got the --

A. Sure.

Q. -- red dots showing you the --

A. Sure.

Q. -- sidewall core data. All right, the blue line, as I understood it, is the neutron density crossplot line?

A. That's correct.

Q. Okay. Did you perform the crossplotting technique that is shown on this exhibit, or did someone else do it?

A. This is just the Schlumberger digital log curve that's calculated by Schlumberger when the logs are run.

Q. Is there anything up to this point that someone

else has helped you perform in crossplotting this?

A. I'm not sure what your question is.

Q. Is this your work?

A. Yes.

Q. Was there anyone else involved in helping you do this?

A. No.

Q. All right. If I understand, the method or the technique is that once you do the crossplotting and generate this blue line you put your core data in that column -- that's what the red dots represent --

A. That's right.

Q. -- core data points -- and then you make a geologic judgment about how to adjust the blue line in relation to the core data points, correct?

A. No, the way it works is, this is all digital data from the core and digital data from the neutron density, and all I did was display them in the same porosity, so they're in the same place on the porosity scale. So there's been no adjustment by me. I've just merely displayed the data.

Q. All right. Do you make the decision on how to adjust the blue line, or is that done by the computer software program?

A. This is just strictly Schlumberger's neutron

density crossplot that's calculated at the time the well is logged.

Q. Yes, sir. Now, how do I integrate the core data? Do I run the software program again, or do you make a choice as the geologist?

A. I'm not sure. Are you asking why I picked those points or what? I just went through and said give me a sidewall, you know, at these different depths, and Schlumberger went in and took the sidewall cores. And then I take that data and send it off to be analyzed by Core Lab to determine porosity.

Q. Okay. You've not, then, made any adjustments; you've just posted the data --

A. Exactly.

Q. -- run the software program, and you have not put any correction factors, adjustments into the analysis at this point, right?

A. That's correct.

Q. All right. When I see the horizontal red line that says TB22-2 on the display --

A. Right.

Q. -- why have you included everything above that line?

A. Gee, I don't know. I was just trying to show -- you know, we had quite a few core samples over this

section, and I just displayed most of them, just kind of what fit on the page.

Q. Does it affect your calculation --

A. No.

Q. -- by adding or subtracting vertical distances in the analysis?

A. No, all the analysis, you know, as far as the footage goes as net feet, is between those two lines at TB22 and TB32.

Q. All right. So between TB22-2 and -32-2, that is the area of analysis, correct?

A. That's right, that's what was used in determining the net feet and average porosity.

Q. All right. What is the significance of the green stuff on the left?

A. The green is a corrected gamma-ray curve, which is also a curve that we run routinely on carbonate wells because you have a difficult time just looking at a standard gamma-ray curve, and some carbonates have a lot of hot response to them, so we run the corrected gamma-ray curve to help us identify what's potential pay and what's not.

So that curve that's shaded olive color is a curve that we use to help us identify pay, and we chose a 30-API-unit cutoff. That's what we've used for a cutoff on

the gamma-ray response.

Q. Other than that correction in the gamma-ray --

A. There's no correction.

Q. You used a cutoff?

A. Yes.

Q. All right. Are there any corrections made to any of the data to adjust it in any way?

A. No, strictly LAS data right out of Schlumberger's data, we just downloaded it.

Q. Mr. Von Rhee ought to be able to take this data, apply your technique and duplicate your result on the net porosity, correct?

A. Yes.

Q. There's nothing you haven't told him yet, that would preclude him from duplicating your work?

A. That's correct.

Q. All right, so we get down to the Matthews 12; at the bottom -- second number up after all those letters is 0.065. So the end result of this analysis is that you believe the Matthews 12 through this interval has a net-pay porosity of 6 1/2 percent?

A. That's correct.

Q. Okay.

A. That's using the two cutoffs that I've talked about.

Q. Now, when we get to 12, which is the two-well digitized comparison --

A. Yes.

Q. -- I look to the right. Is everything on the right log, which is Matthews 12 --

A. Yes.

Q. -- exactly the same as you displayed on Exhibit 11?

A. The logs are the same, there's no manipulation of any of the data. All it is is, I colored in -- The blue curve on the first display was not colored in over the 4-percent crossplot, and I only did that so you could see the red dots easier.

Q. All right, so there's no corrections, no geologic judgment made between this portion of 12 and what we saw on Exhibit 11?

A. It's the same data.

Q. All right. Now we're moving over to the Barber 12. Are you applying the exact same technique to the analysis of the Barber 12 as you applied to the Matthews 12?

A. That's correct.

Q. No changes in technique?

A. No.

Q. You didn't add or subtract any kind of values,

components or any of that kind of stuff?

A. No, sir.

Q. All right. So if Mr. Von Rhee is duplicating your technique, he ought to be able to duplicate the conclusion, which is your analysis that the net-pay porosity in the Barber 12 is 6.7 percent?

A. That's correct.

Q. All right. In the documents filed in exchange between the parties, there was a November 6th document that showed the use of 8.7 as the net-pay porosity value used by Mr. Travis, Conoco's engineer --

MR. TRAVIS: Mr. Lowe.

MR. KELLAHIN: I'm sorry, Mr. Travis is my guy. Mr. Lowe.

Q. (By Mr. Kellahin) Mr. Lowe's calculation used an 8.7 net porosity, right?

A. Yeah, well, I don't really get -- He used a value, and I'm not sure what that number is, I --

Q. My question for you is, did you help him get that value in November?

A. I think all this stuff was just a cursory look. We haven't done a detailed analysis until we actually digitize this log and use these cutoffs that I mentioned.

Q. All right. So in this analysis here, on Exhibit 12, did you supply Mr. Lowe with this porosity value, the

6.6?

A. Once these values were calculated, I supplied them to Mr. Lowe.

Q. All right, so that's where he got the 6.6?

A. Yes.

Q. You don't know where he got the 8.7?

A. That's correct.

Q. All right.

A. Well, you know, this thing has been going on for quite a while, as you recall. And so we've used different times, and like I said just a few minutes ago, it's all been a pretty cursory look, just trying to give us a number to use to see what kind of ballpark drainage radius we have, whether it's real large or real small.

You know, it's not been a real detailed analysis, not until we digitize this data and had it analyzed, you know, on half-foot increments. You know, we were just doing some rough calculations, and they weren't as accurate as this has been. So any previous work that's been done is not as accurate as this. And as Sapient has done, they did a cursory look, and that was kind of our approach on the porosity in the first attempt. This was a more rigorous approach.

Q. All right. Did you supply Mr. Lowe with any other data for him to make his calculations?

A. Mr. Lowe got the net feet and the average porosity that's displayed at the bottom of this chart, and he also was supplied with pressure data that was acquired on the Matthews 12 well.

Q. Am I correct in understanding, Mr. Denny, that as you reduce the porosity percentage you're going to spread out the acreage affected by the well so that you would have a larger area, correct?

A. Yes, if you move that cutoff this direction, to the left, you can see you're going to reduce your net feet of effective pay as you move in this direction, your net feet are going to get less. We think we've used an optimistic cutoff by having the cutoff towards the right as more feet of pay.

Q. All right. So the answer to my question is yes?

A. Yes.

Q. When you add porosity and change no other value, then you would shrink the size of the container? You would affect smaller areas?

A. As me the question again.

Q. Yes, sir. We're talking about what happens when you change the porosity percentage and nothing else. If you --

A. Porosity percentage.

Q. If you change it from 6 1/2 to 12, you're going

to shrink the drainage area?

A. Six and a half. When you go from 12 down to 6, you're increasing the drainage area.

Q. Exactly, and the reverse is what?

A. When you go from 6 percent up to 12, you're making the drainage radius smaller.

MR. KELLAHIN: No further questions.

CHAIRMAN WROTENBERY: Thank you, Mr. Kellahin.

Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. You've shown us that the porosity trends run northwest-southeast --

A. Yes, ma'am.

Q. -- you've shown us that the structure trends run northwest-southeast, you've shown us that the depositional trend is parallel to the shelf, which is --

A. Well, it's somewhat parallel.

Q. -- to the southwest.

A. Excuse me.

Q. Would you say that the drainage area would be also directional, northwest-southeast?

A. All that isopach was trying to show, Commissioner Bailey, was that in a general sense that's the way the porosity is running. You know, I think you could still get

a radial flow around there. It's just that the thicknesses are different. But if you have continuity between wells in the reservoir, you know, the drainage radius doesn't necessarily have to follow some direction.

And as you can see on this display, we think the correlations are pretty good between the two wells. We think that both -- the Sapient well is affecting this Matthews 12 well.

Q. So in your professional opinion, would you say that the drainage area would be elliptical from northwest to southeast?

A. I really can't say which -- how it would look. I mean, we've got effective pay in all directions around those wells, so it's not necessarily that it would be elliptical.

Q. Would you say that the area of preferred drainage would be to the northwest-southeast?

A. I really don't have enough data to -- You know, I don't have enough data to say what the preferred direction is going to be.

I mean, there's a thicker section of rock, and so if you think that thicker means that the drainage is going to be that way, then I guess it would be that way, but that's not necessarily the case. Permeability doesn't necessarily go hand in hand with porosity, but --

Q. Of course not. But with all the other factors that you brought through, you're leading us to believe the drainage would be preferred northwest-southeast?

A. Well, like I said, I was just trying to show that the porosity is trending that way, versus a north-south direction.

Q. If that is true, looking at the exhibit over here, would drainage be any more -- any stronger in the west half of this quarter section than it would for the entire east half of that -- east half of the east half?

A. I'm sorry, could you --

Q. No one has addressed the configuration of the proration unit for these wells. I'm looking for some evidence to see that the entire northeast quarter should be the proration unit for the Barber well --

A. Yeah.

Q. -- as opposed to the east half of the east half.

A. Oh, I see what you're saying. Oh, I understand. Well, if you just look at thicknesses, we definitely have, we think, a trend going northwest-southeast. And if you equate better thickness to better pay, then we probably would have more drainage in that direction according to the way I've mapped it.

COMMISSIONER BAILEY: That's all I have.

CHAIRMAN WROTENBERY: Commissioner Lee?

EXAMINATION

BY COMMISSIONER LEE:

Q. Well, assuming -- Do you know what's gas cap?

A. Pardon? Do I know what a gas cap is? Is that what you asked me?

Q. Yeah.

A. Well, I know this Sapient well and the --

Q. Okay --

A. -- Barber well are making gas.

Q. -- you make an attempt to write as the gas cap in that area.

Do you have a distinct -- You know, the reservoir is not like a tank, it's not saying you have gas up there, then you have oil down there and that's it, right? Because all you usually get to a little place before the gas comes in.

So in between these two fluids -- I tried to understand your rationale. So in between this fluid the dominant effect is the capillary pressure, right? Do you know what's capillary pressure?

A. Well, yeah, a little bit. I'm no expert on it. I'd rather defer --

Q. So why --

A. -- those questions to the engineer.

Q. -- why do you make an attempt -- I think you're

right, okay? I think you're right. In general, up there you have more gas, down there you have less gas. The reason of that is because you don't have a distinct line for the oil and gas, because the capillary pressure would mess it up.

A. I see.

Q. So in other words, you're right, okay? It's mixed. So -- But in general, up there is more gas --

A. Yes.

Q. -- down there is more oil; is that what you --

A. Yes.

Q. -- you're trying to say?

A. Yes, sir.

COMMISSIONER LEE: Okay. Well, that's it. Thank you.

THE WITNESS: Thank you.

EXAMINATION

BY CHAIRMAN WROTENBERY:

Q. Mr. Denny, could you clarify for me the status of your Matthews Number 12? It has been completed --

A. Yes, ma'am.

Q. -- at this point? Is it producing?

A. Yes, ma'am.

Q. And the unorthodox location was approved by the Division last fall, you testified. What pool is that well

producing in?

A. It's in the West Monument-Tubb Gas.

Q. Okay. And what is the acreage assigned to that well?

A. 160-acre square proration unit.

Q. So it's the southeast quarter --

A. -- of 6.

Q. -- of Section 6?

A. Uh-huh.

CHAIRMAN WROTENBERY: That's all I had. Did you have any redirect, Mr. Carr?

MR. CARR: No, I do not.

THE WITNESS: That well is making 300 and some MCF right now.

CHAIRMAN WROTENBERY: Thank you.

THE WITNESS: We've been producing it for, I don't know, a week or so. I can't remember when it exactly came on but it hasn't been too long, a week or ten days.

CHAIRMAN WROTENBERY: Thank you for your testimony, Mr. Denny.

We will take a ten-minute here before the final witness.

(Thereupon, a recess was taken at 3:13 p.m.)

(The following proceedings had at 3:22 p.m.)

CHAIRMAN WROTENBERY: I think we're ready when

you are.

MR. CARR: I'm ready.

CHAIRMAN WROTENBERY: Okay.

ROBERT J. LOWE,

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

DIRECT EXAMINATION

BY MR. CARR:

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

A. My name is Robert James Lowe.

Q. Mr. Lowe, where do you reside?

A. Midland, Texas.

Q. By whom are you employed?

A. Conoco.

Q. What is your position with Conoco?

A. I'm a reservoir engineer with the southeast New Mexico Hobbs group.

Q. Have you previously testified before the New Mexico Oil Conservation Commission?

A. Not the Commission, just the Examiner.

Q. Would you briefly summarize for the Commission your educational background?

A. I received my bachelor's degree from -- My undergraduate studies were at the University of Wyoming. I attended the University of Southern California for a

master's.

Q. And your degrees were in -- ?

A. Both in petroleum engineering.

Q. Could you review your work experience since graduation?

A. I worked five years in Wyoming, both carbonates as well as sandstones there. I then worked five years -- I was recruited to go over to California where I worked there for five years as well, at Elk Hills. Once again, I was recruited by a manager who was there, who took on a position over in the Middle East. I worked in the Middle East for three years, decided to move my family back to the United States, at which time we moved back to Midland, Texas. I worked the Permian Basin with Marathon for about three years, and then I joined with Conoco here in February of this year.

Q. Are you familiar with the Applications filed in this consolidated case on behalf of Sapient?

A. Yes, I am.

Q. Have you made an engineering study of the area which is involved in this case?

A. Yes, I have.

Q. Are you prepared to share the results of that work with the Oil Conservation Commission?

A. Yes, I am.

MR. CARR: We tender Mr. Lowe as an expert witness in reservoir engineering.

MR. KELLAHIN: No objection.

CHAIRMAN WROTENBERY: We accept Mr. Lowe's qualifications.

Q. (By Mr. Carr) Have you prepared exhibits for presentation here today?

A. I have.

Q. Let's go to what has been marked as Chevron/Conoco Revised Exhibit 6. Let's identify the exhibit and then review it for the Commission.

A. Okay, what you see before you is a production plot for Sapient's Barber B Number 12.

As you see, the well was completed in the Tubb in August of 1999. The rate that you see here in front of you is the daily gas rate. In December of 1999, the well was frac'd and put on production at the end. It then produced for a period of time.

What's not marked on here, you can see there's a brown line which goes through the data. That is the decline that was used for forecasting the ultimate recoverable reserves. And as you can probably pick out, the sixth and seventh star in 2001 refers to June and July. Those rates are below the decline, because the well was choked back due to pipeline constraints, does not show the

true productivity of the well.

After -- This was also indicative of a number of wells in the area that were having problems. They identified a problem in the well due to scaling, which they went in and cleaned out as annotated here on the production plot.

Q. You've come up with a decline rate of what percent?

A. Thirty percent.

Q. And how does this compare to Sapient?

A. Sapient's is 43 percent.

Q. And what do you think is the -- accounts for that difference?

A. They are declining through the period in which the well was choked back, clearly you can see during the months of June and July, which steepens it quite a bit.

Q. Let's go to, now, Exhibit Number 7. This is the original Exhibit Number 7. Identify it and review, it please.

A. I have similar production plots here -- these are in calendar day -- gas, oil and water. These are for the three Marathon wells that are in Section 5. The well numbers are the Bertha Barber Number 16, the Bertha Barber Number 17 and the Bertha Barber Number 18. It might be useful to kind of refer to your structural map that Mr.

Denny provided for you, which I believe is Exhibit Number 4.

Q. That's correct.

A. What I've -- Let me quickly also point out, the format is the same for all three wells.

The line with the circles, filled-in circles, that is the calendar-day oil.

The rather faint -- or not-as-dark line but with the stars at each point, that is the gas production.

And the upper one, upper curve here, with the crosses at each individual point, that is the GOR.

And what you note in looking at each of these three wells is that first of all they're producing at a much lower GOR than the Sapient well is. Cumulative production from the Sapient is 1.2 million cubic feet per barrel -- in other words, a GOR of 1.2 million -- whereas these are in the neighborhood of 4000 to 10,000. Clearly, these are on the oil leg.

The other thing you'll note, if you'll look at the trend of the GOR, these indicate that these are being supported from a gas cap expansion. They are not dropping off significantly through the productive life, suggesting this is a depletion drive. And when looking at this well, validates the structure map that Mr. Denny has provided to you about the relationship of these wells with the

structure.

Q. All right, Mr. Lowe, let's go out of order now. Let's go to what has been marked as the Chevron/Conoco Exhibit 13.

A. It's the determination of initial pressure. What this shows are basically the exact -- the DSTs that Sapient was trying to provide, and it was simply to show the methodology which Conoco was using to try to come at the initial reservoir pressure is basically the industry standard. What you do is, you go in and obviously normalize it to a pressure gradient and then correct it to a common data point.

What we did here was, as we went through, there were obviously a number of wells that seemed to be quite low, indicating depletion. There are some other wells that were quite high, suggesting perhaps they were starting to get into perhaps more of an oil leg. We were interested in what the pressure gradient was in the gas cap.

So what I did was, I threw out the lowest two, I threw out the highest two, and calculated a pressure gradient and used that to arrive at what the pressure would be at the midpoint perforation. And as Sapient said, this is the appropriate method about calculating it.

The other way about doing it is taking all of the data into account. As you can see, the average for using

all the pressure points is a much lower pressure gradient of 0.348, versus 0.386, or what was used in the material balance as well as volumetrics.

Using the average of all the data would suggest that the initial reservoir pressure was actually 2200 pounds. The fact that we're using 2468 assumes the fact that there has been no depletion from this structure, when in fact the Marathon wells have been producing longer and prior to the Sapient well.

As to whether these wells actually have any corresponding effect, I have no idea. I have no pressure data from those wells. Unfortunately, as both parties recognize, is the fact that we have no initial pressure in this structure. We're just using our best estimates and industry standards here.

Q. And how does your work compare to the work of Sapient?

A. It's coming in about 130 pounds less than what they used for their material balance and their volumetrics, which is significant. Because if you look at it from the straight line, if you lower at the Y intercept, as a result it projects out even further where it crosses the X axis, giving more reserves.

Q. And this is one fundamental difference between --

A. It's one of them. It boils down to, ladies and

gentlemen, three things. I'll make it real clear, real basic. Pressure, it's coming down to porosity and drainage. It's basically those three things. Whether you -- However you interpret the geology or whatever, if you basically focus on those three things I think you'll come to a reasonable solution to what this is all about.

Q. Let's go to Exhibit 8, let's take a look at your volumetric decline analysis work. This is also an exhibit that's been revised; is that correct, Mr. Lowe?

A. Yes, it incorporates the data from the Matthews -- or I shouldn't incorporates, but it is based on the interpretation that's been applied to the Sapient well on how to come up with the porosity values and the net thickness.

Q. Now, there is an error we've discovered in this exhibit, is there not?

A. There is.

Q. And what is that?

A. It's at the very end of the --

MR. TRAVIS: Excuse me, what exhibit?

MR. CARR: We're on Exhibit 8 (Revised).

MR. KELLAHIN: This one.

MR. TRAVIS: Okay, thank you.

THE WITNESS: It's under the decline calculations, and it's at the very end. What I might do is

just go ahead and proceed, if I -- might be okay, and then identify it, because it's the very last entry, where the drainage radius as of September 1st.

Q. (By Mr. Carr) All right, let's go through the exhibit --

A. Okay.

Q. -- volumetrics.

A. Volumetrics, this is the porosity, as we've earlier spoke about. This is based on sidewall core. Bottom line is, you can run all the logs you want, but you've got to correct it back to the reservoir. You've got to correct it back to the core to try to come up with it.

And then for -- The fact that we have a very good correlation between the crossplot and the core gives us a high degree of confidence of what our average porosity values are.

From the definitions that Mr. Denny has discussed -- he's come up with his net thickness -- we looked at how much volume there would be in 160 acres, also applying our pressure gradient to come up with an initial pressure at the midpoint perforation. Based on that, it's saying that the initial gas in place is about 1.76 BCF of gas.

We then went through and estimated an abandonment pressure of 250 p.s.i., calculated our Z factors, based on the Benedict-Webb-Rubin equation of state, and we are

coming up with a recovery factor of about 92 percent.

Based on this, it tells us that we have .3813 million cubic feet per acre foot, or our ultimate recovery would be 1.6 BCF.

If we look at the decline calculations, we're showing the 30 percent, constant percentage, our projected rate of 883, our final rate of 50 MCF. Ultimate recovery is showing it to be 1.67 BCF.

Applying the same recovery factor here, we're showing that this well would recover 165 acres. This results in a drainage area -- drainage radius, pardon me, of 1500 feet.

This is the area -- This was an improper calculation. We've recovered 49 percent so far, but the actual drainage radius to date, based on 818 million cubic feet, is not 741 as shown in front of you, but over 1000 feet, 1060.

Q. And so the 741 should be changed to 1060?

A. That's correct.

Q. Using each of these methods, you have a fairly substantial agreement; is that correct?

A. Yes, I do.

Q. And based on that and the -- what numbers you've used and explained how you got them, what is your confidence level in the number -- areas you've predicted

are drained by this well?

A. Very high. I've also gone through a material balance, which corresponds to these calculations as well.

Q. And will we show that later?

A. Okay.

Q. Let's go and, before we move on, ask you if you would like to take a minute and compare some of the figures that Chevron and Conoco are using, as opposed to those that are actually being utilized by Sapient. First, we have porosity, correct?

A. Yes.

Q. We are using what?

A. I believe they're using a little over 12 percent, we're using 6.6.

Q. And we're taking it off of the information provided by Mr. Denny in his Exhibits 11 and 12?

A. That's correct.

Q. As to the pressure information that we're using, how does this compare with what --

A. Our initial --

Q. -- is being used by Sapient?

A. Our initial pressure is about 130 pounds less. Ours is based on a pressure gradient normalized to a common datum. Their pressures were from deeper in the formations. They went through and averaged them in calculating their

volumetrics and material balance and presenting on the charts.

Q. And we're using a 30-percent decline instead of a 46, as you've indicated?

A. 43, I believe, is --

Q. 43 --

A. -- what they use.

Q. -- okay. If we look at the information we now have on the decline rates that have been used by Sapient, does, in fact, the well's current performance even fit with the reservoir parameters that we've been looking at?

A. Well, that's something we'll -- I think we're probably going to be talking about here fairly soon. Chevron/Texaco went in and ran a pressure buildup. From the pressure buildup they saw no boundary effects. They -- The pressures, the actual raw pressures, were actually 100 pounds higher than what was being recorded in Sapient's wells. This is not accounting for the pressure interpretation on extrapolation during our type-curve fitting.

But the bottom line is that --

COMMISSIONER LEE: What's the type curve you're talking about?

THE WITNESS: Should I go ahead?

Q. (By Mr. Carr) Yeah, let's go ahead, and is that

the curve that is shown on Exhibit 14?

A. No, we did not supply a type curve fit --

Q. All right.

A. -- although I do have a copy of it here. It is basically a finite fracture model. This well had been acid-stimulated above the parting pressure.

After doing the type-curve fitting, we used the porosities from the type curve and generated a simulation through both the log log plot, the cartesian plot and the Horner plot and got an exact fit.

COMMISSIONER LEE: So you have a multiple solution, right? You can alter the other parameters and get to what you needed, right? You don't need permeability?

THE WITNESS: I did not enter permeability into it.

COMMISSIONER LEE: For a type curve you have to, right?

THE WITNESS: Type curve, no, it's dimensionless, it's based on dimensionless time.

COMMISSIONER LEE: Dimensionless -- You have a permeability there, right?

THE WITNESS: I think it calculates it based on the steady-state flow through the Horner plot.

COMMISSIONER LEE: What is the T_d --

THE WITNESS: T_d?

COMMISSIONER LEE: -- dimensionless time?

THE WITNESS: Dimensionless time? The dimensionless time at what point?

COMMISSIONER LEE: I mean T_d, what is the solution of T_d?

THE WITNESS: You're going to have, I believe -- I don't have the exact --

COMMISSIONER LEE: K_t --

THE WITNESS: -- I believe porosity is involved.

COMMISSIONER LEE: You have a permeability there. Dimensionless --

THE WITNESS: The T_d -- Well, the permeability has come from identifying the radial flow --

COMMISSIONER LEE: It's a slope?

THE WITNESS: Yes. -- and identifying it on the Horner plot, is what we identified it from.

COMMISSIONER LEE: Okay.

THE WITNESS: And we were able to see that we were able to --

COMMISSIONER LEE: The T_d is equal to K_t divided by $\mu C\phi$, divided by R_w. So if you don't know ϕ, you don't K.

THE WITNESS: But we believe we know ϕ, sir.

COMMISSIONER LEE: Then you plug in ϕ to get a K.

Then you use K to calculate the other parameters, right?

THE WITNESS: That's what I was saying, yeah.

CHAIRMAN WROTENBERY: Go ahead.

Q. (By Mr. Carr) All right, Mr. Lowe --

A. Okay.

Q. -- I'm going to have Mr. Kellahin explain that to me after the hearing.

A. Well, as Mr. Lee said, we input the porosity into it. Based on the porosity and what we identify as the radial flow, we're able to identify the permeability and then internally calculate it.

Q. All right, Mr. Lowe, let's go to Exhibit 14 --

A. Okay.

Q. -- a new exhibit, and I'd ask you to identify the exhibit and review the information on it for the Commission.

A. Okay. Once again, we're showing the initial conditions here. I apologize for the double decimal point at the end, but it's basically the same number, as you can tell.

The bottomhole pressure that was observed and corrected down to the mid-point perforations, what would have been equivalent there at the Sapient well, would have been 1446. This is after the well had produced 818 million cubic feet of gas.

As you can see, the straight line on the plot, it extrapolates it out until we reach an abandonment pressure of 250 pounds. That says that at that point in time we will have produced 1.68 BCF.

If you continue to extrapolate that blue line where it intercepts the zero line, it shows that the gas in place would be 1.83 BCF.

Q. Mr. Lowe, what conclusions can you draw from your engineering work on this reservoir?

A. Based on this, we're seeing that the material balance is very much in agreement with what we're forecasting both on decline and in volumetric. It is using industry standards for identifying pressures, it is using the industry standard for correlating core with crossplot porosity. And it simply shows that this well is draining well beyond 60 acres. It is draining our acreage to the west, based on a radial drainage pattern.

Q. Are you ready to go to your drainage --

A. Yes.

Q. -- radius overlays?

A. Yes.

Q. Let's go to Exhibit Number 9, and you should have an overlay which is marked Exhibit 9.

A. You'll want to pull out and look at a structure map here. This overlay is scaled to match your structure.

Q. Which is Exhibit 5, I believe?

A. I believe it's Number 4.

Q. Exhibit 4.

A. On the overlay you'll see a green hached -- or a crosshair, if you will. That green crosshair goes on the intersection or to the northeast of the Sapient Number 12 where the sections intersect.

You will notice the red dot from the overlay lies directly over --

Q. Wait just a minute --

A. Oh, I'm sorry.

Q. -- let me take out Exhibit 9.

A. Okay, you will notice that the red dot from the overlay overlies directly over to the Matthews Number 12 well. There are two circles that are on the overlay. One is a blue circle indicating an initial reservoir pressure of 2462. The red one is an indication of a potential of depletion of a Pi of 1900 p.s.i.

CHAIRMAN WROTENBERY: Just to make sure we've got the right exhibit, our red dot overlays the Sapient --

THE WITNESS: That's correct.

CHAIRMAN WROTENBERY: -- Barber Number 12. Okay, I'm sorry --

THE WITNESS: Correct --

CHAIRMAN WROTENBERY: -- I thought you said --

THE WITNESS: -- Sapient --

CHAIRMAN WROTENBERY: -- Matthews, but --

THE WITNESS: Sapient Number 12, yes.

CHAIRMAN WROTENBERY: Okay.

THE WITNESS: And what this overlay is showing, the drainage area of the Sapient, Barber B -- or Bertha Barber Number 12.

Q. (By Mr. Carr) And the two circles, again, Rob, are what?

A. And the two circles are the drainage area for the Sapient Bertha Barber Number 12 if the initial pressure was 2462 or if the initial pressure was 1900.

Q. And what is the source of those two pressures?

A. The source of the two pressures, the Pi is based, as I mentioned beforehand, on a regional pressure gradient.

The 1900 is just the potential that there may have already been some initial depletion from the Marathon well. There's no indication that there has been, it's just showing the effect if there was.

Q. You were present earlier today when there was testimony about, even if we have a well that drained 160 acres, what would be the effect of putting that on an 80-acre spacing pattern?

A. It would drain our acreage. We have been abiding by the rules and regulations of the Oil and Gas Commission,

therefore we would not have -- we have not been allowed to drill a well on the western half of this 160 acreage that has been ordered for the Sapient well. We clearly would not be -- we've -- If we were to drill a well now, we would not get the same rates, the same volumes, obviously the same value for the gas.

We have also lost the value of that revenue because -- well, revenue that's been generated two years ago, Sapient has had the luxury of being able to earn interest off of this revenue, where we have not had access to our revenue associated with it.

Q. So if we look at overlay 9, we can see one well, we can see the well -- the projected drainage area. It drains Sapient acreage in the east half of the northeast, it also drains the Conoco/Chevron federal lease in the west half of the northeast; is that right?

A. It has been and continues to illegally produce, yes. Or it has been until October.

Q. What does your Exhibit Number 10, the overlay that's marked Exhibit Number 10, show us?

A. Number 10 shows the effects of going to an 80-acre proration unit, that it promotes waste and lack of conservation.

Q. So if we went ahead and with wells that drain 160 acres, put them on 80-acre spacing -- it was suggested

might be appropriate -- this is what we get, is it not?

A. Yes, it would. Now, I might just describe real quickly, once again you have a green cross there that fits on the intersection of the sections. You have a red dot that will fit on Sapient's Number 12 well. What it implies is that if you go to 80 acres, then people are going to have to start drilling offset wells to protect or try to gain what little correlative rights they -- or reserves they still have, that has not been drained from Sapient.

Based on, you know, if each well was able to drill or complete, drain 160 acres, you see the overlap which would basically not have happened. It would require additional wells. We're really not recovering that much more additional gas.

Q. In your opinion, would this be an imprudent way to develop the reservoir?

A. Yes, it would be.

Q. What are your recommendations to the Commission?

A. My recommendation is that we would not accept the nonstandard proration unit that has been requested, that we maintain the order of the Examiner on the 160 acres.

Q. If we go with 160-acre spacing, there is no retroactive aspect of the case, is there not?

A. That's correct.

Q. If there's an 80-acre spacing rule adopted, the

retroactivity issue is before the Commission; is that right?

A. That's correct.

Q. And what is the impact of retroactively changing the spacing?

A. Retroactively changing the spacing. This well has started draining our area. They have been receiving -- As a result, they have not only been producing the royalties and the reserves of Conoco, et al., but also the royalty interests that we represent.

We are now facing an area where the well is producing at a lower rate to try to recover these same volumes. It would take a much longer time now that there's been depletion occurring. We no longer have the luxury of higher prices that the well was incurring at the time that it was producing as well.

Q. In your opinion, will approval of 80-acre spacing for the West Tubb-Monument Gas Pool result in wasteful drilling practices?

A. Yes, it would.

Q. Would it impair the correlative rights of the interest owners in that pool?

A. Yes, it would.

Q. Is it in the best interest of conservation?

A. No, it's not.

Q. Were Exhibits 6 through 10, 13 and 14 prepared by you or compiled under your direction?

A. Six through 10, 13 and 14, yes.

MR. CARR: At this time we move the admission of Chevron/Conoco Exhibits 6 through 10, 13 and 14.

MR. KELLAHIN: No objection.

CHAIRMAN WROTENBERY: Exhibits 6 through 10, 13 and 14 are admitted into evidence. I'll just note for the record that 6 is a revised exhibit and 8 is a revised.

MR. CARR: Thank you. I pass the witness.

CHAIRMAN WROTENBERY: Mr. Kellahin?

MR. KELLAHIN: Thank you.

CROSS-EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Lowe, to help me stay oriented and to ask you some questions, would you mind finding a copy of Mr. Denny's Exhibit Number 4, which is his structure map revised? Do you have that before you?

A. Yes, I do.

Q. All right. I want to talk to you for a moment about the drive mechanism in the reservoir and what you as a reservoir engineer believe is occurring. I want to focus on the Marathon wells in the west half of Section 5. There's a population of Tubb wells that are classified oil wells, and the display shows the gas-oil ratio at some

point in time. Do you see those wells?

A. Are you talking about the structure map?

Q. Yeah, I'm looking at the structure map.

A. Yes.

Q. Do you find the Marathon wells?

A. Yes.

Q. All right. This is independent of the gas wells -- let's set aside the Sapient well, Barber 12, and Chevron's Matthews 12 -- those three oil wells or four oil wells are producing by a solution gas drive mechanism, are they not?

A. I think it's a solution gas drive and gas cap expansion.

Q. All right. If there is a gas cap associated with the production, the gas cap would involve the Chevron Matthews 12 and the Sapient Barber 12, right? Is that what we would see off this display?

A. Could you ask that one more time --

Q. Yeah.

A. -- I'm sorry.

Q. You said it was a combination solution gas drive and a gas cap expansion?

A. Yes, as you deplete the pressure around those wells.

Q. Can you have both, or do you have to choose one

over the other?

A. No, it's going to be -- one's got to be a primary -- I believe the gas cap would probably be the primary mechanism here.

Q. Where is the gas cap?

A. It is upstructure of these wells.

Q. Upstructure of the Marathon wells?

A. Yes, sir, as indicated by the production from the Barber 12, which suggests that -- and I believe even Sapient has concluded that there's a structural component with a gas cap on top.

Q. Now, if you're in a solution gas drive reservoir and you're below the bubble point of the reservoir, you can have oil production from wells that have a gas-oil ratio that increases over time? That's how that critter works, isn't it?

A. Except it falls off quite quickly, sir. That's not exactly true. You'll have -- if you look at the Turner equations and production, you'll have a rapid production of gas, because it has a higher mobility than oil. And then during the lives of the well, the gas production will fall off. I believe that even Sapient has some other wells in the Tubb where you can see a decline in GOR. Those probably would be solution GOR.

Q. All right, that's in the early life of a

reservoir, that's going to happen, right? We're going to get gas expansion --

A. I'm just saying solution GOR. You would have a rapid increase in GOR, and then it would -- It would rapidly go up and then tail off like that. Mobility of gas in the well, in the reservoir, can produce much quicker as you fall below the bubble point. If you have a gas cap expansion, it's just constantly going to either maintain or start increasing on your GOR, as indicated.

Q. All right, what evidence do you have in this area that it's one or the other?

A. As the exhibits -- I believe it was Number 7, there were three plots of the Marathon wells where we saw an inclining or increasing GOR. This is typical for a gas cap expansion.

Q. Would it also not be -- Isn't it also typical of a solution gas-drive reservoir that's below the bubble point?

A. Solution GOR below the bubble point will not continually increase over the life of the well.

Q. Do you see a direct correlation between the gas withdrawal from the Sapient well and any effect on any of the Marathon oil?

A. No, sir, I do not.

Q. Do you have any PVT from the Marathon wells?

A. No, unfortunately. I work for Conoco now, so I don't have that information with Conoco.

Q. So no part of your conclusion or position is predicated on having analyzed PVT data?

A. No, sir.

Q. When we look at the management of this part of the Tubb field by the regulators, are you suggesting that we ought to create an associated pool where we control the gas withdrawals from the gas cap in order to save the drive mechanism for the oil wells?

A. I think it's almost kind of an academic state at this point in time. If we would have done this at the time that the Sapient was first developed, we might have had some benefit. This well has been illegally producing for two years. We've produced half of the volume in place, the damage is done. I really don't know if -- I think that perhaps it might want to be looked into as what the optimum production rate might be. But as to eliminating the benefits, I think -- as I stated before, I think the damage has been done from two years of production.

Q. And that damage is predicated on your belief that the Sapient well is draining approximately 165 acres by your calculation?

A. Actually, it's more than that. What we clearly see, as I mentioned to myself, it boils down to three

things; one is the drainage area and one is pressure. If you look at the drainage radius that is being advocated by Sapient, they're saying that this well has only drained about 59 to 60 acres. That drainage area would be 670 feet today.

But we know well that 730 feet away the Matthews Number 12, the pressure is now 1440 instead of nearly 2500 pounds. This well has depleted beyond -- at least to the Matthews well, if not beyond.

Q. All right, it could be accounted by the shape --

A. This is rock-hard evidence showing that the well is producing -- or depleting more than 60 acres.

Q. All right, let's talk about your rock-hard evidence. Conoco has no interest in the southeast quarter of 6, correct?

A. No, sir.

Q. The drainage effect by the Sapient 12 on the Matthew 12 does not effect your correlative rights, does it?

A. The drainage area --

Q. No, sir, that's not my question.

A. I'm sorry, I --

Q. Did you hear the question?

A. No, I'm trying to repeat what you were saying.

Q. All right, sir. The question was, Conoco has no

interest in the southeast quarter of 6 --

A. That's correct.

Q. -- has no interest in the Matthews 12 well --

A. That's correct.

Q. -- and if drainage is being affected by performance of the Sapient well, correlative rights of Conoco are not impaired?

A. The Sapient well, as we've already discussed, has already drained to the Matthews Number 12 well.

Q. I'm willing to concede that to you, sir. But if you don't have any interest in that well, Conoco's correlative rights are not impaired?

A. No --

MR. CARR: I would request that Mr. Lowe be allowed to finish his answer before Mr. Kellahin engages in any more argument with him.

MR. KELLAHIN: Madame Chairman, I'd like the witness to be responsive to the question and not use my question as an excuse for a narrative.

CHAIRMAN WROTENBERY: Well, it would help me, I think, if you would restate your question. I was having a little trouble understanding --

MR. KELLAHIN: All right.

CHAIRMAN WROTENBERY: -- what you were asking.

Q. (By Mr. Kellahin) Conoco's interest is confined

to the west half of the northeast of 7, correct?

A. Conoco's interest?

Q. Yes, sir.

A. Conoco's interest is -- with respect to the Sapient Well Number 12, as you stated, is on the west half of the northeast --

Q. All right, sir.

A. -- yes, sir.

Q. In the southeast of 6, Conoco has no interest?

A. That's correct.

Q. You have no interest in the Matthew 12 well?

A. No.

Q. If the Matthew 12 and the Barber 12 are too close together, or if Sapient is draining Chevron, it doesn't affect Conoco's correlative rights, correct?

A. Correlative? It implies the fact that the drainage area is even much larger than what is being suggested from Sapient's information that it's been presented to the Commission. And from the standpoint of our correlative issues, it is inferred, then, that the acreage on the western half of that 160 is also being drained.

Q. Have you attempted to create an overlay using 60 acres of drainage and see what happens?

A. No, sir, I have not.

Q. Are you aware that the Division in Case 10,984, heard on May of 1994, on an application by Texaco to amend the special pool rules, has findings in Order R-10,128 declaring that this is a solution gas drive reservoir? Are you aware of that case?

A. No, sir, I'm not.

Q. Would you go with me, Mr. Lowe, to your Exhibit Number 6 (Revised)? It's a production plot.

A. Uh-huh.

Q. I'm going to distribute two other production plots, Mr. Lowe. I've got the one from the March 1st hearing that you testified to, and the second one I have is the original Exhibit 6. It's dated November 6th of this year, and it is also your work. Let me take a moment and distribute those.

Mr. Lowe, let me do these chronologically with you, sir.

A. Uh-huh.

Q. If you'll take what is Conoco Exhibit 3 from the March 1st hearing, the data block in the upper right shows, based upon this production decline curve that you prepared, that you have a 16-percent decline and an estimated ultimate recovery of 2.8 BCF. Do you see that?

A. Yes, sir.

Q. The strategy for you and other reservoir

engineers is, attempt to forecast by production decline an estimated ultimate recovery, and you do that by drawing a straight line, correct?

A. That is correct.

Q. And the strategy is to make a judgment in an attempt to honor or intersect as many of the data points that you think are reasonable?

A. That we have at the time, yes, sir.

Q. When we look at the March 1st exhibit, you intersect two data points. One is early in the year 2000, and then you intersect a second point in about July, I think, of 2000, and then forecast beyond that point, all right?

A. No -- Well, intersect, yes. There's also some data that is above that as well.

Q. And I assume you use your engineering judgment to exclude those?

A. The data points above?

Q. The ones above and below, you make some judgment about --

A. I'm trying to come up with what is generally the overall trend.

Q. All right, sir. The next display is Exhibit 6, the November 6th date on this. This is the one you revised, and you submitted the revision today. I want to

look at the November 6th draft of the exhibit.

Here now, you've changed the decline from 16 percent to 22 percent. That results in an EUR of 2.15. You've dropped it about half a BCF, and you've attempted to cut or intersect certain data points on the production plot, right?

A. Tried to look at that data, where -- what was conceivably data that I knew that was not being affected by constraints or choking back.

Q. All right. By this line, you have picked a starting point of early in the year 2000, and then you've forecasted this line at a certain rate of decline, correct?

A. (No response)

Q. What happens -- What happens if you make the judgment to start in the fall of the year 2000 -- And see the highest data point to the right of the little downward curve in the production data? Do you see that point?

A. The highest point of the downward --

Q. All right, let me find it for you. In the year 2000, if you count from the end of the year 2000 --

A. Yes.

Q. -- count back four months --

A. Okay.

Q. -- that looks like September production.

A. Let's see, December, November --

Q. -- October, September.

A. -- October, September.

Q. If you start with that and put your point there and forecast it forward through the next four data points, you're going to get an EUR that's less than what you forecasted on this plot?

A. I could have very easily forecasted it through, as you spoke about the September 2000, through those next three data points in 2000, and then the next two points, and raised the ultimate projection, giving actually more reserves than what I'm forecasting here.

Q. All right. Let's go to the one you utilized for today. It's Exhibit 6 revised. Do you have that before you?

A. Yes, sir.

Q. All right. It appears to me that you have no more data points between November 6th and December 4th, correct?

A. Correct.

Q. Same data points, no more information in which to construct the curve, correct?

A. That's correct.

Q. And yet you choose to change it to a 30-percent decline, for an estimated EUR of 1.67?

A. The reason for -- If you look at 2001, there is

-- one, two, three, four, five, so this would have been May. I was not accounting for the May as being a valid point. When I started looking through the stay to the order hearings, it noted the fact that the well was, in fact, producing at full capability in May, and I decided to honor that point, thus giving a steeper decline.

Q. Now, look at September of the year 2000 through February of 2001.

A. September of 2000.

Q. Yes, sir, where we started a while ago.

A. Uh-huh.

Q. And go to February of 2001.

A. Uh-huh.

Q. Those are all full months of production, aren't they?

A. Yes. I could have easily raised that decline to fit through those data points, giving a higher cum. I decided to be more conservative and have it slightly lower.

Q. Did you lower it in order to match the EUR you have got off your production, P/Z curve?

A. No, sir, that was just by -- it was a situation I didn't have that at the time. As I said, I tried to honor the May data in 2001, which previously I thought was an invalid test.

Q. Okay. Mr. Travis in Exhibit 14 this morning

provided the Commission with a tabulation of the various engineering assumptions he had made in his calculations. Do you remember that display?

A. Yes, I believe --

Q. Let me show you a copy.

A. I think I do, but -- Yeah, okay.

Q. Exhibit 14, he's given you a checklist of the assumptions he's made.

A. Okay.

Q. Do you have a similar spreadsheet for us to show the engineering assumptions you've made in your processing of this data?

A. I believe they're pretty much spelled out in the handouts here --

Q. All right.

A. -- for --

COMMISSIONER LEE: Exhibit Number 14?

THE WITNESS: Exhibit Number 14, and I believe also Number 8.

Q. (By Mr. Kellahin) Okay, let's go to 14 first. Now, we're talking about your Number 14, Mr. Lowe.

A. I might just hold these up to make sure that I have the right numbers here.

So is that the Number 8? You see the volumetrics and decline. And I believe the Number 14 is the material

balance calculation.

Q. All right. If you'll flip through Mr. Travis's exhibit book --

A. Uh-huh.

Q. -- and find his Exhibit 18, let's compare the material balances.

A. Okay.

Q. The first difference is the initial bottomhole pressure?

A. Yes, sir.

Q. You have a lower pressure than Mr. Travis used, right?

A. Yes, sir.

Q. All right. Let's go now to your spreadsheet, which is where you got your average pressures for that initial bottomhole pressure. It's your Exhibit Number 13.

A. My Exhibit Number -- ?

Q. -- 13. I'm trying to --

A. Yes.

Q. -- back through to see --

A. Yes.

Q. -- where you got the 2468.

A. As I said, that was based on a regional pressure gradient and corrected to the datum point in the Sapient well.

Q. Let's talk about the method you utilized on Exhibit 13.

A. Okay.

Q. If I remember your testimony, on Exhibit 13 you exclude two of the pressures.

A. I exclude four, sir.

Q. Well, first of all you exclude two of the lowest --

A. Yes, sir.

Q. -- and two of the highest?

A. That's correct.

Q. All right. The purpose in excluding two of the lowest would be that they appear to be substantially different than the other pressures and might adversely affect your calculation if included?

A. No, sir, what they imply -- at least to me, I'm not sure about someone else, but it would imply to me when looking at these pressure gradients that we had depletion in these wells, and we're wanting to look at a conservative aspect, saying that, okay, let's assume that there was no depletion here.

The effects of that is, in order to produce the same volume of gas under a depleted scenario or a lower pressure means that you have to drain even a larger area. And we are wanting to be conservative in saying, No, we're

going to say the structure is at initial reservoir pressure; there has been no depletion to this point in time.

Q. If that's your method, why throw out the top two highest?

A. They also -- We are also wanting to look at pressure gradients that are reflective of a gas-cap well, or a gas well. The higher pressures indicate to me that you are now starting to get a fluid gradient in here, and because the liquids are heavier than gas, the densities are heavier, they will give a higher pressure gradient. We're looking for a pressure gradient in the gas cap.

Q. So you and Mr. Travis are going to disagree on how you arrive at what you believe to be the appropriate initial bottomhole pressure for purposes of the calculation?

A. I believe even -- and I apologize, I don't remember your geologist's -- your name.

Q. Von Rhee.

A. Von Rhee. I believe he even stated that this was the appropriate method for calculating the pressure.

Q. I don't believe he said it was appropriate to throw out the highest; I think he was talking about averaging these pressures. But we'll let him speak for himself in a moment.

A. Okay.

Q. Let me ask you, when we go to Chevron Exhibit 14, now, and compare it to Sapient's Exhibit 18, your pressure is lower --

A. Can I call that Conoco's?

Q. Sure. What did I call it?

A. Chevron's.

Q. I'm sorry. Conoco's Exhibit 14.

A. Okay.

Q. If all other factors are unchanged, am I correct in understanding that the effect of you using a lower initial pressure will be that you're going to get a higher EUR than Mr. Travis?

A. There are -- That is correct.

Q. Okay.

A. When looking at the material balance --

Q. Yes.

A. -- as charted here, if you use a lower pressure than what they've used, it will extrapolate out to being a higher recoverable gas in place.

Q. Just trying to have a list of the differences and how you've arrived at the differences.

And the other point I want to look at is what you've done with the bottomhole pressure on the Barber 12 well that Sapient took in the seven-day test in October.

When I look at Conoco Exhibit 14, I see some dates.

A. This date is -- This was a typographical error on my part, I apologize to everyone.

Q. All right, so you're not using different data, it --

A. No --

Q. -- it didn't exist. It's the October data, right?

A. This is the November data from -- This should have been, I believe, 11-26 of 2001. This was the pressure seen at the Chevron well.

Q. Okay, let's make the comparison now to Sapient Exhibit 18.

CHAIRMAN WROTENBERY: May I just make sure I've got the right information here? Are we looking at your Exhibit Number 14?

THE WITNESS: Yes, we are.

CHAIRMAN WROTENBERY: And --

THE WITNESS: So where it says --

CHAIRMAN WROTENBERY: -- where is the --

THE WITNESS: -- bottomhole pressure 9 -- September 6th, that should actually read bottomhole pressure of November 26.

CHAIRMAN WROTENBERY: Okay, November 26th?

THE WITNESS: Yeah.

MR. KELLAHIN: All right.

THE WITNESS: There was very little production at the time that Chevron's Matthew Number 12 was produced, and therefore we feel that this is a representative pressure of the entire reservoir, not a localized event.

Q. (By Mr. Kellahin) All right, let me make sure I understand what you've done. If your mission as a reservoir engineer is to calculate the drainage area for the Barber 12 well, instead of using Mr. Travis's bottomhole pressure test from his well you substitute the pressure from the Matthews 12 well?

A. I wouldn't say substitute. I would say I used the pressure at PE, which is effectively out near this -- as we start to get away at the Matthews Number 12.

Q. All right. Am I correct in understanding, though, the difference in how you've gotten --

A. That's correct, that is another difference. The difference is, we are showing an initial pressure based on a regional gradient, and we are using a pressure that is away out further in the reservoir area, towards the boundaries or the areal extent.

Q. Let's see what happens when you do that.

A. Uh-huh.

Q. We get down to the P/Z adjusted pressure. It's the 1801.6, correct? On the Conoco exhibit.

A. P/Z --

Q. What did I say?

A. P divided by -- I thought you said adjusted pressure.

Q. P/Z. 1801.6.

A. Yes, sir.

Q. If you'll look over on Mr. Travis's Exhibit 18, you see his October 24th adjusted pressure, and I think it's the 1477 number?

A. Yes.

Q. For purposes of the calculation, that's the number that goes into --

A. -- this chart.

Q. Into the chart, okay. The effect of you using a higher bottomhole pressure at this point in time is going to increase the ultimate recovery estimated for the Sapient well over what Mr. Travis has calculated?

A. That is correct.

Q. Okay.

A. In fact, if we look at the raw data from the Matthews well, it was about 100 pounds higher than what was reported by the Sapient well.

Q. Okay. Let's go down to the graph at the bottom.

A. Yes.

Q. If you'll turn to -- Let's see, that's Conoco

Exhibit 14 again. If you'll look through the book there, Mr. Lowe, and help me find the Sapient Exhibit 19.

A. Okay, you're looking at a chart --

Q. Well, I was hopeful to look at a table there. You've got a --

A. I've got a --

Q. -- a graph?

A. I've got -- Number 19 is your --

Q. Yes, sir.

A. -- P/Z.

Q. All right.

A. Okay.

Q. Am I comparing the same part of the method when I look at your P/Z versus cum and compare it to Mr. Travis's Exhibit 19?

A. Yes, sir, you are.

Q. Okay. It appears to me that the starting point on the vertical axis is -- appears to be the same?

A. No, it's going to -- ours is -- the one that I provided was 3200.

Q. All right.

A. If you look at the pressure point, I believe, for the -- They're about a hundred pounds higher.

Q. Okay. As you move down the plot --

A. Uh-huh.

Q. -- on your P/Z --

A. Yes, sir.

Q. -- there's a point identified as 818. What is that?

A. That is the cumulative volume that was sold as of through September, as reported by Dynegy, from the Sapient well, that it produced 818 million cubic feet, which I believe is pretty much in line with what you have been discussing.

Q. All right, as you continue further down the line using this material-balance method, you get a point where you stop with an abandonment pressure of 250 pounds?

A. Yes, sir.

Q. That's what I'm looking at?

A. Yes, sir.

Q. You've calculated, then, 1.68 BCF of EUR?

A. That's correct.

Q. When we look over at Mr. Travis's exhibit --

A. Yes.

Q. -- he's using an abandonment pressure of 300 pounds --

A. Uh-huh.

Q. -- and it shows that his EUR is going to be 1.3 BCF --

A. 50 pounds, maybe, to answer your question --

Q. Yeah.

A. -- as what the difference might be, is negligible.

Q. Okay, all right.

A. Yeah, and I think even Mr. Travis commented on that.

Q. Let's look at the volumetrics and see what happens.

A. Uh-huh. Is this back to, now, Exhibit 8 of mine?

Q. Yes, sir, it's going to be your original Exhibit 8 and your revised Exhibit 8. I'll give you the original.

A. Okay, thank you.

Q. Do I remember correctly, Mr. Lowe, that back in March -- I'm trying to think. I think Conoco used 12-percent porosity, or did you use 10?

A. I can't remember. I believe we used a higher porosity cutoff, though --

Q. All right.

A. -- which would have given a higher porosity value than using the 4-percent porosity cutoff.

Q. I think yours was 12, and Mr. Denny's was 10. All right, if we use 12 you came to a certain conclusion about EUR. Since then you've had more time and opportunity to look at this, and you have prepared an exhibit marked November 6th. Let's look at that.

When I look at November 6th and compare it December 4th, again, the Conoco displays --

A. Uh-huh.

Q. -- what has changed in any of these input values?

A. The porosity that is actually using core data now --

A. -- to arrive --

Q. Okay.

Q. Before utilizing the core data, where did you get the 8.7 porosity value used in the first entry on the November 6th spreadsheet?

A. I believe Mr. Denny had tried to come up with an estimated average, just looking at it from the paper log, whereas the 6.6, he went in and digitized it, using the cutoff that he's explained here to the Commission.

Q. All right.

A. A much -- a more rigorous way.

Q. That's your recollection, is the 8.7 came through Mr. Denny --

A. Yes, sir.

Q. -- to you? All right.

The only difference in the calculation, then, between November 6th and the December 4th spreadsheet is a change in the porosity value? It went to 6.6?

A. That's correct, that and the fact that on the

decline I realized that there was a data point that I needed to honor, giving a steeper decline rate.

Q. All right, the decline went from 25.2 to 35.7?

A. That's on a nominal decline. The actual constant percentage decline went from 22 to 30 percent.

Q. I'm sorry, I misread that. I see that. Any other changes?

A. No --

Q. Okay. Again, as --

A. -- other than the fact, I apologize, I had used an abandonment pressure originally of -- We had used a 250-p.s.i. abandonment pressure in the hearing in March. I was going through, just seeing if -- to verify some of the calculations of if their drainage radius was smaller and what Sapient had testified as an abandonment pressure at 300. There was a typo error of 300 but, as we described, 50 pounds in the abandonment doesn't result that much in reserve differences.

Q. If you lower the abandonment pressure from 300 to 250, that will, in fact, increase the EUR?

A. Slightly, but not significantly.

Q. The biggest component of change here is what is the appropriate porosity value to use in the calculation?

A. I would say initial pressure and porosity.

Q. All right. And the higher the porosity, the

smaller the drainage area. And conversely, the lower the porosity, the larger the drainage area?

A. That's correct. And I think that's what it gets down, is the major difference is between porosity and pressure and drainage.

Q. Is there any other variable between you and Mr. Travis that we've not discussed? When we look at the Barbara 12 well, you've analyzed the pressure on that one, and now you have data on the Matthews 12?

A. Barbara?

Q. Barber, the Sapient Barber 12. You've got the bottomhole pressure?

A. I have the bottomhole pressure. Unfortunately, the gauge was not run down to the midpoint-perfs. This was a well that had been stimulated with liquids, was cleaning up with liquids, and we have no idea if it's a gas below the seating nipple or if there's liquids below it. The assumption at this point in time is that it's gas, but as I say, it was cleaning up with liquids; it could be liquids as well, resulting in a higher pressure.

Q. Let's look at the Matthews 12, which is the Chevron well. When we look at the pressure data from that well --

A. Yes.

Q. -- has the Matthews 12 been perforated in the

exact same correlative intervals as was perforated in the Barber 12?

A. I have not looked at the correlative intervals from the standpoint of Matthews Number 12. That would be a question better suited for a geologist and Chevron.

Q. So you don't know whether or not the pressure in the Matthews 12 has been influenced or affected by getting picked up in an interval in the Tubb that's not present in the Barber 12 well?

A. The interval, the top interval, corresponds with that. But as for the actual sub-correlations, I have not looked at sub-correlations.

MR. KELLAHIN: Thank you, Madame Chairman, that concludes my examination.

CHAIRMAN WROTENBERY: Thank you, Mr. Kellahin.

Commissioner Bailey?

COMMISSIONER BAILEY: No questions.

CHAIRMAN WROTENBERY: Commissioner Lee?

COMMISSIONER LEE: Yes.

EXAMINATION

BY COMMISSIONER LEE:

Q. I'm confused about the solution drive. Mr. Kellahin asked you solution drive, and you tried to answer it -- you tried to answer it, you know, the solution drive, when we learn the solution mechanism. Is that producing

the oil or producing the gas?

A. That's producing the oil.

Q. And right now do you think your system -- right now are they producing oil only?

A. No, I believe that some of these wells in the Marathon have perforated, perhaps, into the gas.

Q. So they do not have -- In your opinion, they do not have a solution gas drive --

A. No, sir.

Q. -- predominant? Okay, I just wanted to make sure.

The second one, let me -- There's a lot of data here, and I think basically you can answer for me. I think Chevron and Conoco tried to prove the drainage is large?

A. Yes, sir.

Q. And Sapient is trying to say the drainage is small?

A. Yes, sir.

Q. So there are three so-called scientific parameters you're trying to get. One is the thickness. You decided to use 26.5, and they decided to use 30. So each side chose their favorite one, because smaller one, certainly you have a bigger drainage, right?

A. Even more significant, I think, perhaps --

Q. Yeah, let me --

A. Sure.

Q. Okay --

A. Sure.

Q. -- I don't want to agree with you, okay?

So the porosity, of course, the higher the porosity, the higher -- the higher the porosity, the less drainage will be?

A. That's correct.

Q. So Chevron and Conoco choose 6.6 scientifically?

A. Yes, sir.

Q. And Sapient choose 12 percent scientifically?

A. I would say they're rather unorthodox.

Q. But they think they're scientific?

A. I would just state, I think most people in industry would not use a PE method for backing in.

Q. Okay. So then going to -- I'm saying -- I'm -- Right now, you know what I'm trying to do is, you all choose your favorite -- the number, okay?

The saturation of the water, you choose 28 percent, and 27 percent, that's -- Okay? It's not much -- Of course, it's favorite of each side also.

But with these three data the key thing is to estimate the gas in place?

A. Yes, sir.

Q. Right? Gas in place is on top of everything,

because you have to estimate a gas in place. And so here comes the decline curve, because the gas in place is the data, right? This is a decline curve, right? Look at this decline curve.

This decline curve -- Chevron/Conoco choose from 16, 21 and 30, or if they stick with the 16, the drainage will be large, it will cover the whole section. Is that true?

A. If the 1.6 BCF --

Q. Initially you choose 16 --

A. Oh, 16 decline --

Q. -- you choose 30-percent decline, it's in favor of Sapient?

A. Well, yeah, at the point in time as they specified, we were unaware of the fact they had the well choked.

Q. Okay, so Sapient chose 47 --

A. Not --

Q. -- 47.3?

A. -- not originally, sir. They had a 20-percent decline, I think.

Q. 20-percent decline, so they go to 43?

A. Yes, sir.

Q. So their number is higher than yours. So guarantee they calculate a drainage that's smaller than

yours?

A. Yes, sir.

Q. All right. Of course, this is done scientifically.

Then the bottomhole pressure, that's another -- bottomhole pressure. Which bottomhole pressure? Try to --

CHAIRMAN WROTENBERY: Are you talking about the initial --

COMMISSIONER LEE: No, bottomhole pressure. I have here -- Oh, here. Now, look at this. This is the bottomhole pressure, right?

CHAIRMAN WROTENBERY: Which exhibit are you looking at?

THE WITNESS: Material balance.

COMMISSIONER LEE: I'm looking at the Number 14 of Conoco and Chevron.

THE WITNESS: The material-balance method?

Q. (By Commissioner Lee) Material-balance method.

A. Okay.

Q. This is the key. Fortunately, we all agree, we say initial point, both sides, initial point. The problem is, the only data we have -- the first data point is pretty much -- is estimated, right?

A. That's correct.

Q. Nobody knows what it is you have, but you agree,

right?

Then the differences is between the middle point. And middle point, you are assuming one hundred forty -- 1446, and the other side say it's 1235, right? If you stick with his number, then you've got his value, right?

A. If I use his pressure and assume that there's --

Q. Right.

A. -- no liquids below their --

Q. Right.

A. -- gauge.

Q. And right now he's got an advantage, he's got an advantage, saying, Well, I have the real data, right? You've got the shut-in data, you have shut-in data.

However, both sides, you agree, the initial pressure is 2461, right?

A. (Nods)

Q. And right now your well is 1446, right?

A. That was based on a six-day shut-in.

Q. Right, six-day shut-in.

A. Yes, sir.

Q. Right? Where did the gas go? That's to your disadvantage. Where did the gas go?

A. Where did the gas go?

Q. Yeah. You're supposed to -- If everybody believes we're not interfering with each other, so you

drill the well, then I perforate it, I should get a 2461?

A. That's correct, sir. Yes, sir --

Q. And right now you only got 1446?

A. We have drained --

Q. So that's for your disadvantage, you have to defend that, right? Okay, summarize this and -- if you agree?

A. I agree.

COMMISSIONER LEE: Okay, thank you.

CHAIRMAN WROTENBERY: Thank you. Any redirect of this witness?

MR. CARR: No redirect.

CHAIRMAN WROTENBERY: Okay, thank you.

MR. KELLAHIN: May we have a short recess and decide if we want to put on any rebuttal testimony --

CHAIRMAN WROTENBERY: Yes, sir.

MR. KELLAHIN: -- if we have time to do that?

CHAIRMAN WROTENBERY: Yes, we can do that.

MR. KELLAHIN: May we take a break?

CHAIRMAN WROTENBERY: Yes.

Thank you for your testimony, Mr. Lowe.

THE WITNESS: Thank you very much, appreciate it.

(Thereupon, a recess was taken at 4:36 p.m.)

(The following proceedings had at 4:44 p.m.)

CHAIRMAN WROTENBERY: Mr. Von Rhee is back.

MR. KELLAHIN: With your permission, Madame Chairman, I would like to call Mr. Von Rhee for a couple of specific questions responding to Mr. Denny's core analysis position.

CHAIRMAN WROTENBERY: Fine.

ROBERT W. VON RHEE (Recalled),

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Von Rhee, let's start with Mr. Denny's Exhibit Number 11. That is the digitized log that has the Matthews 12 on it. Mr. Denny has got the core points posted on that display.

When he talks about having sidewall core data, what does that mean to you and how significant is it to you?

A. Everybody in this business knows that if you can get core data, get core data. It's what we like to see, to look at the rocks.

But I would just like to comment a little bit. We have a reservoir, a highly complex dolomite, limestone and sandstone. It has variability on the order of feet, it has variability on the order of inches. And you can look in one side of the wellbore and see 18-percent porosity,

you could look on the other side of the wellbore and see 3-percent porosity.

So you have a little device that goes in there and takes a little one-inch-diameter core and takes a look at the rock, and you hope that it's representative. So we'd just like to comment that -- And Chevron very nicely supplied us with the data, and we did have an opportunity to review the data, and I found that 21 plugs or core samples were taken within the overall Tubb interval, and it represents about 1 percent of the vertical height of the reservoir.

So do we have a representative sample? Well, you know, we've only sampled 1 percent when you think about it, little 1-inch plugs. If we get meaningful data, perhaps we are lucky or perhaps we picked really good points, and I don't know how that was decided on.

The other thing about this particular exhibit, Mr. Denny says, Look at the great map. Well, exhibits can be just a little bit misleading. And if you look at this exhibit, each one of the red dots is about 1 1/2 porosity units wide. And we're dealing with fairly low porosity to begin with, porosity that's only on the order of 3, 4, 5, 6, 8, 9 percent.

So 1-1/2-percent width of the dots means that somewhere in there is the real data, but that's equal to

about 25-percent error against the 6.5-percent average porosity. So if you actually plot the log crossplot porosity versus the core data point, you find that there's an error that's more like 2 1/2 percent higher or lower. It's equal to about a 40-percent difference, one way or the other. And some of the samples had errors in excess of 100 percent.

So there is an overall interesting correlation, but I don't say that it is statistically the final word in that regard.

Q. Let me ask you about Exhibit 12, Mr. Denny's Exhibit 12. You heard his testimony, did you?

A. Yes.

Q. You've been able to examine his exhibit prior to hearing, have you not?

A. Yes.

Q. You understand his technique and method in handling the analysis of the core?

A. Yes.

Q. And the crossplotting of the porosity value that he used?

A. Yes.

Q. Were you able to duplicate Mr. Denny's result for the Chevron Matthews 12 well using his technique?

A. I got pretty close.

Q. How close is close?

A. The Exhibit 12 shows a porosity on the average, a crossplot, of 6.5 percent. I performed the crossplot porosity calculation for the digital data they supplied us within the pay intervals that I have defined, and I got a value of 6.8 percent crossplot porosity.

Q. Mr. Denny in his testimony said that he applied the same identical method to the Barber 12 well analysis that he did to the Matthews 12 analysis. Were you able to take his method and obtain the same conclusion that he obtained?

A. No.

Q. What did you get?

A. I applied the same methodology to match the porosity, and I arrived at a crossplotted porosity of 8.4 percent and cannot tell you wherein the difference lies except a bust in digitizing of the log data or something else like that, because I just -- I tried as I could, I could not reproduce that number as I had for the Matthews Number 12.

Q. So using the same methodology and technique that Mr. Denny used for the Matthews 12, you got 8.4-percent porosity for the Barber 12?

A. That's correct.

MR. KELLAHIN: No further questions of Mr. Von

Rhee.

CHAIRMAN WROTENBERY: Mr. Carr?

MR. CARR: No questions.

CHAIRMAN WROTENBERY: Commissioners?

COMMISSIONER BAILEY: (Shakes head)

COMMISSIONER LEE: (Shakes head)

CHAIRMAN WROTENBERY: Thank you, Mr. Von Rhee.

MR. KELLAHIN: I'd like to call Mr. Kyle Travis as a rebuttal witness.

CHAIRMAN WROTENBERY: Mr. Travis?

PAUL KYLE TRAVIS (Recalled),

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Travis, I'd like to give you the opportunity to respond to Mr. Lowe's testimony and conclusions, as well as those conclusions and testimony of Mr. Denny that's applicable to your reservoir engineering analysis.

Let's start with the drive mechanism of the reservoir and talk about your opinion of what's going on in this area.

A. All right. As I think you pointed out, Tom, that in the field rules hearing for the Monument-Tubb field, they called it a solution gas drive reservoir.

I think what you actually have out here is a number of solution gas drive reservoirs. You've got these fingers of porosity coming and going so fast from one location to the next that there is no continuity across the field in specific zones of porosity. There are these intervals, these benches, these zones that we can correlate across the field. But within there, this porosity comes here, this one here, this here, and you have this stratigraphic component.

There is no question that structure adds a component to the gas. I mean, all of those gas wells, the Barber 12 included, are in association with little, localized highs. So there is a component.

Now, one thing we looked at early on -- we didn't prepare it as an exhibit because we didn't anticipate that this was going to go in this direction, but we looked at subsea intervals versus the GOR and came up with a plot like this, that shows you're going higher in this direction, and GOR is increasing in this direction.

So it's showing that your highest GOR wells here are in the higher part of the structure, but you also have high-GOR wells here that are structurally low to low-GOR wells here. So --

Q. Just a minute, Mr. Travis. This is, in fact, Exhibit 26 and --

A. Oh, I'm sorry. Okay, so it's in there. I didn't realize that was included. Let's pull it out. And -- Well, I'll wait till you pull it out.

Q. All right, sir, go ahead.

A. We're not trying to quantify anything with this, it was just trying to create a visual aid that would help you guys understand -- all of us understand, Mr. Kellahin included -- the complexity of this reservoir and the lack of homogeneity, the heterogeneity of this reservoir.

So does that help any, Dr. Lee? I don't know.

Okay, I was just trying to give us a better understanding there. All right.

Q. Let me ask you this. Mr. Von Rhee has taken the digitized analysis that you talked about that Mr. Denny had for Exhibit 12, and he's come up with a porosity value of 8.4 percent. Have you taken that number, put it into your calculation and estimated for us what impact that would have, if that's the right number --

A. Yes, I have.

Q. -- on what the drainage is?

A. Right. I've plugged that number into our material balance -- I mean into our drainage calculation and came up with 88 acres drainage. Significantly larger than the 60 acres, but still points to an 80 acres being the appropriate spacing. And that again -- the 60 acres

explains the drainage all the way into the Matthews 12 well. The 88 acres would obviously explain it even further.

That's probably a good point to talk about the Matthews 12 and their pressure. Dr. Lee, you were pointing out the differences in our cases, and one of the key points is that second pressure point. We measured the pressure in our well, they measured the pressure in their well.

What was not discussed by anybody, if we could get out Conoco/Chevron Exhibit Number 12 and look at it -- All right, the perforations in each well are marked in red bars. You can see that top porosity zone, although it's present in the Matthews 12 well, is not perforated. The other intervals, there are rough tie between what's perforated, except for there's other zone down here. If you look in the Matthews 12 well, the well on the right, all the way down at about 6382, you see that porosity streak there. And their perforations go down into that.

We do not have that porosity streak in our well. Here we are 700 feet away, and a whole new porosity streak has developed, which is saying exactly what we've been trying to say all morning and afternoon, that you have these streaks of porosity come and go in these -- This is 700 feet away. If you drill a well over in the east half -- excuse me, the west half of the northeast quarter, you're

going to find some other zones like this that pop in.

If this thing is not developed up on 80 acres, you're going to miss opportunities like that, there's going to be reserves left behind, and it will -- reserves will be left in the ground.

Q. Let's talk about Commissioner Bailey's question a while ago, about having the Commission decide an orientation to the 80-acre spacing units if the Commission decides in Sapient's favor. Is there a relationship to either the original gas in place or some other reservoir characteristic that would cause you to recommend an orientation of north-half/south-half or east-half/west-half?

A. You know, that is a difficult question. And Mr. Denny really struggled with that, because the -- You know, as I understand it in New Mexico, I think -- I thought the operator got to delineate which way the 80 acres went.

Q. Well, Mr. Travis, the operator does in most instances, but --

A. Okay.

Q. -- I wanted you to answer a question.

A. All right. What makes it so difficult, Tom, is, we have this isopach that we developed, and as each geologist testified, you do the best job you can. But you're dealing with a 6-inch hole in the ground or an 8-

inch hole in the ground and measuring out -- some logs measure out this far, some this far. But you're measuring a very small area.

And then, you know, you get these points with 30 foot, with 12 foot, with 15 foot, and you do the best job you can drawing an isopach map.

And then you deepen the Matthews 12 well and you have a 20-point go to 32-point -- 32 feet. So this thing can change so rapidly, you know, it is really hard to say how this stuff is going to drain. If the thickness and everything is truly running north and south, then you probably are going to have a north-south trend to the drainage.

Q. Let's talk about the assumption that Mr. Lowe made. Mr. Lowe made the assumption that he was going to have radial drainage and it will drain in a circle, that the drainage circle for the Barber 12 well --

A. Excuse me, Tom, are you talking about Exhibit -- Was there an exhibit number?

Q. There was an overlay, we haven't --

A. The overlay.

Q. -- gotten to this one --

A. Okay --

Q. -- we're talking about --

A. -- I'm sorry.

Q. -- we're talking about the Conoco overlay. They've got a drainage circle. And if we don't have definitive science on how to draw the shape of the drainage circle, we default to a circle?

A. Yes.

Q. As the Matthews 12 well competes with the Barber 12, that competition is going to set up a no-flow boundary between those two wells?

A. That is correct.

Q. So north and south, you establish equity with those wells?

A. Correct.

Q. And they're there?

A. Correct.

Q. When we look at the east-west dimension, do you have a display that shows the impact of 60-acre drainage circles on the development of hydrocarbons in the northeast quarter of 7? I've marked it as Exhibit 33.

A. Yes.

Q. All right.

A. What did you assign? 33?

Q. It's not stamped, I apologize for that. I will do that after the hearing, if I may.

All right, on Exhibit 33 you've drawn some circles. What have you drawn?

A. All right, actually one of these circles was Conoco's circle. It was the 159-acre drainage that they were saying at one time the well would drill [*sic*]. And with their overlay, if you just take it by itself, the quarter section isn't marked, and so it makes it look like that 160 acres was draining a whole lot more of that northeast quarter than it really was.

So we imposed both our 60-acre drainage circle and their 159- or 160-acre drainage circle around the Barber 12 well to show the effect on not only the acres in 6 but the rest of the northeast quarter of 7.

And what -- Of course, we don't feel it's going to drain 160 acres. But what this is saying, taking their own circle and putting it on there, that if this thing is spaced on 160 acres, that 70 percent of that west half is not going to get drained. Even with their own data they're saying, You need 80-acre spacing.

Q. If we look at your conclusion about 60-acre drainage circles, describe for us the potential impact on the Conoco interest in the west half of the northeast quarter.

A. It's going to be minimal, but if -- likely, if the Matthews 12 is already being affected, then the effect of our well over there has probably reached into the very sliver up there, the very corner of that 80 acres, which

would be the west half of the northeast. But ultimately it will affect only a small area, and I think with them drilling their own well in there they could make that effect negligible.

Q. If the Commission agrees with you and approves 80-acre spacing for a gas pool that's equivalent to the oil pool rules, stands up the spacing unit, then there is an opportunity for Conoco and Chevron to exercise their correlative rights in the west half of the northeast quarter and recover their share of hydrocarbons from the Tubb?

A. Right. And if they desire to, it will be their option whether they drill another well also in the west half of the southeast of 6.

Q. And under your proposed rule change, they could be as close as 330 feet to the west line of the east half of the northeast quarter?

A. They could.

Q. The west boundary of your spacing unit --

A. Right.

Q. -- they could 330 from that line?

A. They could.

Q. All right. Please continue, Mr. Travis.

A. Okay. The other thing I wanted to discuss was the porosity calculations themselves. Mr. Denny testified,

you know, that his core data validated his analysis, but an observation I made -- Did Chevron provide the raw core data to the Commission? Was that an exhibit? I lost track.

Q. I think that was just exchanged between the parties.

A. Okay. Well then, I'll just give you the observation I have from their data.

They -- Denny made a big deal that we didn't use gamma-ray cutoffs, and that -- one of the reasons -- a good example why one shouldn't, if you look at their own core data they have -- you know, they cut 23, 25 core points -- they have core points number 20 and number 16, which they counted as pay. Okay, 20 and 16. And these zones had 6.4-percent porosity and 4-percent porosity, so they exceeded his cutoff.

Their permeability, however, was less than .01 millidarcies and .01 millidarcies, so very tight rock.

Okay, now let's look at some points that were excluded only because of shale content. Points Number 12, 14, 15, 18 and 19 all have porosity above the cutoff, and they have a permeability as high or higher than those other two points which he counted as pay.

So what his -- in effect, what his shale cutoff is doing is, it's discounting rock that contributes as much as rock that he counted as pay. So I think there's a

danger in applying that, and that could explain the difference between the 26 1/2 feet and the 30 feet.

MR. KELLAHIN: Let me have you leave those with the court reporter.

I would like, madame Chairman, to mark those as Sapient Exhibit 34. It's the core data spreadsheets, and we'll do that after the hearing if that's acceptable to you.

THE WITNESS: Okay. Another -- You know, getting to consistency and the presentation -- and Dr. Lee, you did a good job of boiling it down to what points are critical, what points help who, what points hurt who. And the way you presented it, you know, it did look like everybody was just self-serving, everybody just presenting the side that helps them the most.

And the one thing -- I take with that for a few reasons, but a couple I'd like to highlight.

I mentioned when we first did the -- when I first did the porosity and S_w calculation, I came up with 11.8-percent porosity and -- Let me find it. Well, it's 21-something-percent water saturation.

When Mr. Von Rhee did his more detailed look, he came up with 12.2-percent porosity but 28-percent water saturation. The overall effect of those were that they actually reduced our pore volume and reduced -- excuse me,

increased the drainage area. So -- But we felt those numbers were more accurate, were more defendable, and we put them on our exhibit. As soon as we did them, which was in preparation for the November exhibit, that's what our numbers became, and that's what our numbers stayed with.

The Chevron/Texaco/Conoco exhibits showed up for the November 1st hearing with 8.7-percent porosity, a drop from 10 and 12 percent. We asked Mr. Denny where those numbers came from.

He said, Oh, you know, they're just ballpark numbers. Let me see if I can quote him. I wrote down a note somewhere. But anyway, he implied that -- I'll find it. Cursory ballpark values, he thought Mr. Lowe came up with them. Then we asked Mr. Lowe where they came from, and he told us that they came from Mr. Denny.

So here they are getting ready to present to you. A month ago we would have sat down in front of you and they would have been tossing out numbers that they think are cursory ballpark numbers.

And that makes me mad, because I know how much effort we went through to get accurate data and put on the best technical presentation that we can. And for them to come out there and say -- do that and say that, it just infuriates me.

COMMISSIONER LEE: Can I interrupt that?

THE WITNESS: Yes.

COMMISSIONER LEE: I understand that. I understand they changed their number all the time. I know this.

THE WITNESS: Okay.

We truly, truly think that 80 acres is appropriate spacing here. We think these wells are draining something in the 60- to 80-acre range.

But if you believe their exhibit, even if it drains 160, it's not going to drain the west half of the northeast quarter.

80 acres is how the Commission has historically treated gas wells in the Monument-Tubb field, it's an extension of the same depositional rock, the same Tubb deposition, the same heterogeneous reservoir stretching over there, and we think it's appropriate that this area be treated the same way. It's adjoining it. There have already been 23, 24 extensions of the Tubb field boundaries.

CHAIRMAN WROTENBERY: Thank you, Mr. Travis. He's given us a preview of your closing statement, which we were going to receive in writing.

MR. KELLAHIN: Yes, you were. Thank you, that concludes our rebuttal.

CHAIRMAN WROTENBERY: Thank you. Mr. Carr?

CROSS-EXAMINATION

BY MR. CARR:

Q. Just a question, Mr. Travis. You were taking issue, if I understood your testimony, with the way Mr. Denny had used the gamma-ray cutoff; is that --

A. Correct.

Q. Isn't it standard industry practice to use the gamma-ray cutoff in calculating porosity?

A. If it's appropriate. But again, when you have core data that overrides it -- You can't just selectively when you use core data. You have to be consistent.

MR. CARR: That's all.

CHAIRMAN WROTENBERY: Anything else?

COMMISSIONER BAILEY: (Shakes head)

CHAIRMAN WROTENBERY: Thank you very much, Mr. Travis.

THE WITNESS: Thank you.

CHAIRMAN WROTENBERY: Does that conclude your --

MR. KELLAHIN: Yes, ma'am, it does.

MR. CARR: May I have a few minutes to consider surrebuttal?

CHAIRMAN WROTENBERY: Yes, sir, we'll take --

MR. CARR: We don't need it.

CHAIRMAN WROTENBERY: You don't need it? Okay. Thank you. The Commission thanks you.

Okay, I believe that concludes all of the testimony in this case. As we discussed this morning, we will look for closing arguments in written form. And did I understand that you had talked about ten days -- a ten-day deadline --

MR. KELLAHIN: Yes, we did.

CHAIRMAN WROTENBERY: -- so December 14th would be the deadline for submission of the closing statements?

MR. KELLAHIN: Mr. Carr will be in Costa Rica then, but I will be available.

MR. TRAVIS: You could write his.

MR. KELLAHIN: In fact, I could write his.

CHAIRMAN WROTENBERY: I'll let you work that out between the two of you. Thank you, Commissioner Lee.

You did have two exhibits, 33 --

MR. KELLAHIN: 33 is the --

CHAIRMAN WROTENBERY: -- 34 --

MR. KELLAHIN: -- circle, 34 is the core data. With your permission, I'd like those introduced. Exhibit 32 is the letter from Mr. Trautman to Mr. Stogner, that November 9th letter, and so that will be 32. And if you'll allow me the housekeeping, I will get with Steve and we'll take care of those.

CHAIRMAN WROTENBERY: Any objection to the --

MR. CARR: No.

CHAIRMAN WROTENBERY: -- admission of those exhibits into evidence? Okay, get that straightened out.

And -- Anything else we need to take care of.

Okay, thank you, everybody. We appreciate you moving through the material so quickly, thoroughly, and we will take this case under advisement.

(Thereupon, these proceedings were concluded at 5:12 p.m.)

* * *

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 Commission 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 December 15th, 2001.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 2002