STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:	)	CASE NO. 12,122
APPLICATION OF CONOCO, INC., FOR DOWNHOLE COMMINGLING, UNORTHODOX GAS WELL LOCATIONS AND APPROVAL OF A PILOT PROJECT INCLUDING AN EXCEPTION FROM RULE 2(b) OF THE SPECIAL RULES AND REGULATIONS FOR THE BASIN-DAKOTA GAS POOL, RIO ARRIBA COUNTY, NEW MEXICO	)	ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: DAVID R. CATANACH, Hearing Examiner

February 4th, 1999

Santa Fe, New Mexico

99 FEB 18 AM 7:57

This matter came on for hearing before the New Mexico Oil Conservation Division, DAVID R. CATANACH, Hearing Examiner, on Thursday, February 4th, 1999, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, 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

February 4th, 1999
Examiner Hearing
CASE NO. 12,122

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A P P E A R A N C E S

FOR THE DIVISION:

RAND L. CARROLL
Attorney at Law
Legal Counsel to the Division
2040 South Pacheco
Santa Fe, New Mexico 87505

FOR THE APPLICANT:

KELLAHIN & KELLAHIN
117 N. Guadalupe
P.O. Box 2265
Santa Fe, New Mexico 87504-2265
By: W. THOMAS KELLAHIN

FOR THE ESTATE OF GLEN D. HUGHES:

STRATTON & CAVIN, P.A.
320 Gold Avenue, SW
Albuquerque, New Mexico 87102
P.O. Box 1216
Albuquerque, New Mexico 87103
By: SEALY H. CAVIN, JR.

ALSO PRESENT:

FRANK T. CHAVEZ
District Supervisor
Aztec District Office (District 3)
NMOCD

JIM LOVATO
Bureau of Land Management
Farmington, New Mexico

* * *

WHEREUPON, the following proceedings were had at 8:56 a.m.:

EXAMINER CATANACH: At this time we'll call Case 12,122.

MR. CARROLL: Application of Conoco, Inc., for downhole commingling, unorthodox gas well locations and approval of a pilot project including an exception from Rule 2(b) of the Special Rules and Regulations for the Basin-Dakota Gas Pool, Rio Arriba County, New Mexico.

EXAMINER CATANACH: Call for appearances.

MR. KELLAHIN: Mr. Examiner, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin, appearing on behalf of the Applicant. I have four witnesses to be sworn.

MR. CAVIN: Mr. Examiner, Sealy Cavin, Stratton and Cavin law firm in Albuquerque. We're representing the estate of Glen Hughes, and we don't have any witnesses to call.

EXAMINER CATANACH: Any additional appearances?

Will the four witnesses please stand and be sworn in?

(Thereupon, the witnesses were sworn.)

EXAMINER CATANACH: Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Examiner. Our first witness is Mr. Steve Klein.

MR. CARROLL: Pardon me, Mr. Kellahin.

MR. KELLAHIN: Yes, sir?

MR. CARROLL: Do you have an extra copy of the exhibits?

MR. KELLAHIN: I've passed out all my sets. Who needs one?

MR. CARROLL: BLM.

MR. KELLAHIN: Oh, I'm sorry.

(Off the record)

MR. KELLAHIN: Mr. Examiner, I have provided you a page 3 from the prehearing statement. The purpose is to show you some corrections.

This project is a six-well pilot project. We're exploring the opportunity for determining the necessity to increase the well density in the Dakota Pool. And if you'll look at page 3, the corrections are as follows:

Of the six wells in the pilot project, two are at standard locations. The San Juan 28 and 7 has been altered from the south line, and as indicated it should be 1020 feet instead of 1015.

In addition, the next well, the 28 and 7 135-E shows a correction over the Application. The Application said 850 feet from the west line. In fact, that well is proposed to be located 1850 feet.

Of the four wells that are to be at unorthodox well locations, the well identified under the line (c) a the 231-M is correctly named the 280.

The Application, as filed, requested Division approval to drill six pilot wells at these locations in order to gather additional data to determine the appropriate well density for the Basin-Dakota Pool. And as Burlington did in the Blanco-Mesaverde Pool, Conoco desires to start their study with a pilot project. The project is to be conducted in the San Juan 28-7 Unit. It is a federal unit.

The Application had asked for some additional things that are now not necessary, one of which was to have blanket approval for expansion of this pilot project beyond the initial six wells, to include other locations within the unit. It is not our desire to have that approval at this point. If it becomes necessary to expand the pilot, we will come back and ask for additional authority for that expansion.

In addition, we've asked that you approve these four unorthodox well locations. We will demonstrate to you why they are where they propose to be.

And then finally, we have asked for downhole commingling approval to alert you to the fact that these six pilot wells will eventually be commingled between Dakota and Mesaverde. They will be commingled after the appropriate reservoir data has been gathered from the Dakota reservoir and commingled at a subsequent date.

You may decide that you prefer that the commingling request be filed separately under the Division's Form 107. We are compiling that information and will do so if you prefer to have it processed in that fashion. If you want to simply approve it in this pilot project so that these wells can be commingled at a later date, that is certainly acceptable to us, but the choice is yours.

We have four witnesses. We will present a landman, Mr. Steve Klein, who will talk about the correlative-rights issue, the notice questions and the fact that there are no correlative-rights issues of concern to either us or the Division.

We'll then present a geologic overview of the Dakota Pool in the unit so that you can recognize, as the Conoco geologic expert recognize, that the Dakota is a very tight reservoir and that in all probability the current well density is insufficient.

We will present you Conoco's expert on reservoir simulation. He will show you his current status of the simulation work in the unit so that you can understand how they reached the conclusion based upon the data we have now that it's appropriate to institute a pilot so that we can improve ultimate gas recoveries from the Dakota reservoir.

Our final witness is the engineering project manager for this activity, and he will talk to you about the mechanics of how he proposes to do this. He will talk to you about having the economic necessity of having the opportunity to commingle this production, and he stands ready and available to answer questions you might have on the operational aspects of the pilot project.

And with that introduction and your permission, I will proceed with Mr. Klein.

STEVEN C. KLEIN,

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

A. I'm Steven Klein, I'm a senior landman with Conoco, Inc.

Q. Mr. Klein, is it your current responsibility to be the landman in charge of activities for the San Juan 28 and 7 Unit?

A. Yes.

Q. As part of that responsibility, have you examined the current status of that unit to determine the configurations of not only the Dakota participating area but the Mesaverde participating area?

A. Yes.

Q. And you're familiar in a general way with what the technical people desire to do with this project?

A. Yes.

Q. In addition, have you and others for Conoco tabulated all the interest owners in the unit?

A. Yes.

Q. And have you caused notice to be sent to those interest owners?

A. Yes.

Q. In addition, have you sent notice to the offset operators?

A. Yes.

MR. KELLAHIN: We tender Mr. Klein as an expert landman.

EXAMINER CATANACH: Mr. Klein is so qualified.

Q. (By Mr. Kellahin) Mr. Klein, to begin our discussion, let's refer to what is marked as Conoco Exhibit 1.

A. Okay.

MR. KELLAHIN: Mr. Examiner, this plat serves to simply give you a locator of the unit. It is not current as to the status of wells. I think this plat is current as of about 1995, but it does serve the purpose of showing you the location of the unit.

Q. (By Mr. Kellahin) Mr. Klein, describe for us the unit. What type of unit are we dealing with?

A. Okay, this is a federal exploratory unit.

Q. Is this a divided or an undivided unit?

A. This is a divided unit.

Q. What does that mean?

A. Okay, this means that initially the drill block owners were to pay their share of the cost of drilling the individual drill blocks as the unit was developed. As the drill blocks were deemed commercial, they were brought into participating areas for each of the respective formations.

In this case, the Dakota formation has been fully expanded, with the exception of two small tracts in the southern part of the unit, which would not affect our pilot project. And what this means is that anywhere a well is drilled within the Dakota formation, within the pilot project area, the interests are fixed, and all owners would have the same interest, irregardless of where the well was drilled.

Q. So if one of these wells is at an unorthodox location and is encroaching upon an adjoining Dakota spacing unit, that will not matter because the ownership has been consolidated, it is, in fact, common?

A. That is true, yes.

Q. Is that also true if these wells are commingled with the Mesaverde formation?

A. Yes, as to the pilot project wells, the Mesaverde formation participating area does overlap the Dakota in those areas, so the Mesaverde owners' interest would be fixed also.

Q. Let's turn to Exhibit Number 2, Mr. Klein. Has Conoco, prior to filing this case, sent notification to the interest owners in the unit, including offset operators, of Conoco's plan to institute a pilot project to examine increased well density in the Dakota formation within the unit?

A. Yes.

Q. And how was that done, sir?

A. Okay, on December 11th we sent out a courtesy notice, simply to let everyone know what was coming down the road that we were going to file a formal application, and this was just to solicit any concerns that parties might have had before the actual Application was filed. It was simply a courtesy notice.

And then on January 11th is when we went out with our formal mailing of the Application.

Q. And that formal mailing was done by certified mail, return receipt?

A. Yes, yes.

Q. All right, sir. Let's turn now to what you've talked about earlier, the Dakota participating area.

A. Uh-huh.

Q. If you'll turn to Exhibit 3, would you identify and describe that display?

A. Okay, this is a map of the outline of the San Juan 28-7 Unit. The green designates the Dakota participating area within the unit. The pink well spots are the proposed locations for the six wells that we're seeking approval for today. And then we've got the balance of the Dakota wells spotted on the map also.

Q. To the best of your knowledge, is the numbering and the location of the Dakota wells shown on this display accurate?

A. Yes.

Q. The participating area has been expanded to include that area in green?

A. Yes.

Q. Let's turn to the Mesaverde participating area plat. If you'll turn your attention to Exhibit 4, identify and describe this display.

A. Again, this is an outline of our 28-7 Unit. The orange designates the current Mesaverde participating area, and then we have the wellspots for all existing Mesaverde wells within the 28-7 Unit.

Q. All right, sir. Let's turn your attention now to Exhibit 5. Would you identify and describe what you have compiled on Exhibit 5?

A. Okay, Exhibit 5 is simply a listing of all parties that were sent notice of this Application. We have it broken out by working interest owners, carried interest owners, royalty owners, a lengthy list of override owners, and finally offset operators.

Q. Mr. Cavin has entered his appearance today on behalf of the Glen D. Hughes Estate. Are you aware of that?

A. Yes.

Q. At my request, have you examined the interest owner list to determine what Conoco's records show to be the type of interest held by Glen D. Hughes?

A. Yes.

Q. And what is that interest?

A. An overriding royalty interest.

Q. All right. Mr. Cavin indicated that Mr. Hughes is deceased, and he's here on behalf of the estate. Until I advised you of that matter, was Conoco aware that Mr. Hughes had passed away?

A. No, our records still indicated he was living in Albuquerque.

Q. All right. As a result of my request, have you compiled and have we delivered to Mr. Cavin a copy of what Conoco shows to be all the interests of Mr. Hughes and his estate in all formations within the unit?

A. Yes, to our best knowledge, this is the interest in all formations within the unit, that is true.

Q. In your opinion, Mr. Klein, are the interests of the estate adversely affected in any way by the approval of this Application?

A. No.

Q. Let's turn now to the information shown on Exhibit 6. Identify and describe what this tells us.

A. Okay, this is -- With a mail-out this size, we had a certain amount of notices returned as undeliverable. We then researched those and determined where they should be sent, due to address changes, et cetera, and this is a list which shows the additional parties that were sent notice and when the notices were mailed out.

Q. When we look at Exhibit 7, this is your certificate of mailing out the Application and Notice of Hearing for today?

A. Yes.

Q. And when did you have that done?

A. This mail-out was on January 11th.

Q. Approximately how many interest owners did you send notice to?

A. Somewhere around 325.

Q. In your opinion as a landman, Mr. Klein, is approval of this pilot project in the best interests of conservation and protection of correlative rights?

A. Yes.

MR. KELLAHIN: That concludes my examination of Mr. Klein. We move the introduction of his Exhibits 1 through 7.

EXAMINER CATANACH: Exhibits 1 through 7 will be admitted as evidence.

Mr. Cavin?

MR. CAVIN: Yes, sir, Mr. Klein, I just had a few questions for you, please.

EXAMINATION

BY MR. CAVIN:

Q. You indicated that the estate of Glen Hughes owns an override in the 28-7 Unit?

A. Yes.

Q. Okay. Can you tell me which tract that derives from?

A. A number of tracts. I've got a printout here that we can supply you. It varies by formation. In the Dakota formation, which you are concerned with today, he owns under approximately 11 different tracts.

Q. I'm sorry, Mr. Klein, which tract does he own under, not in the participating-area sense, under the basic sense or the lease sense?

A. I'm not sure if I'm understanding your question exactly.

Q. Okay --

A. He owns a small override under a -- probably a number of leases within this unit.

MR. KELLAHIN: Mr. Examiner, if I might interrupt, perhaps it would be useful at this time to introduce what I've marked as Exhibit 7A. It is the data we supplied Mr. Cavin, and it's the discussion that Mr. Cavin is having with Mr. Klein.

EXAMINER CATANACH: Okay.

THE WITNESS: If you're asking specific oil and gas leases, I do not have that information here today.

Q. (By Mr. Cavin) Okay, if you looked at the unit agreement, it would indicate that Mr. Hughes owned an interest in a particular lease --

A. Lease or leases, it could be a number of leases.

Q. Exactly --

A. Right.

Q. -- contribute that to the unit --

A. Right.

Q. -- and you don't know which leases he contributed?

A. No, I do not have that today. That's easily accessible, though.

Q. Okay. Do you know if his interest is committed to the unit?

A. Yes.

MR. CAVIN: Okay. Thank you. I have no further questions.

EXAMINER CATANACH: Okay.

MR. KELLAHIN: Mr. Catanach, we'd ask your permission to introduce Exhibit 7A at this time.

EXAMINER CATANACH: Exhibit 7A will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Klein, were there ultimately some interest owners that you were not able to locate?

A. Yes, and I think in the back of Exhibit 7 I think we've got three envelopes that were returned.

We've also got -- Let me look back here. I think on Exhibit 6, actually, at the bottom, there were a couple.

But there were very few. Out of 325 there was probably no more than a half a dozen. And granted, some of these have come in the last day or so, literally, and we will, when I get back to the office, probably still try to locate these parties.

Q. Have you had any discussion with any of the interest owners that you notified?

A. There have been discussions with the working interest owners on a technical level, and our technical representatives will go into that more later. But there have been discussions with the working interest owners accounting for roughly 97, 98 percent of the working interest within the unit about our project.

And as to override owners or any of the others, I'm not aware that there's been any contact.

Q. Nobody has called you, asking you questions about what you guys are doing --

A. No.

Q. -- or anything like that?

A. No.

Q. No opposition, as far as you know?

A. No.

Q. Do you know why the two small tracts are not in the in the Dakota PA?

A. Yes, back in the early development of this unit, Well Number 109 was drilled back around 1959 by El Paso, and it was deemed noncommercial at the time, and it was produced on a drillblock basis, it was not allowed into the participating area.

At a later date the 109M, it looks like, was drilled -- I don't have a date on that -- immediately to the north. That infill well was deemed commercial, and the land immediately around the infill was brought into the participating area. But the land around the parent well was still excluded.

As far as the Number 151 well, that was drilled approximately 1971, and it's the same case. It was deemed noncommercial at the time for the purposes of including into the participating area, and there has been no infill drilled down there to date, so it has retained the original 320-acre configuration, and it's being produced on a drillblock basis.

But neither of these tracts, of course, will affect our pilot project in any way.

Q. You don't anticipate the Dakota PA to change?

A. No. No, not in regards to the pilot project.

Q. And the Mesaverde PA, is that just not...

A. Right, there have been some Mesaverde wells drilled in some of these tracts that are not included in the PA. Again, those are cases where the wells were deemed noncommercial for the purposes of including them in the participating area. And several of the tracts just have not been developed in the Mesaverde at all.

Q. That could change?

A. That could change, right. But again, for the purposes of our Application today and the six-well pilot project, it would have no effect at all on the ownership at this point in time.

Q. As far as you know, what is the opinion of the other working interest owners in the unit about this pilot project?

A. I hear they're all supportive. Again, I understand we've talked to 97 to 98 percent of the working interest owners. They are supportive. And our technical representatives will go into more of that. They are the ones that have had the primary discussions with these owners.

Q. Your offset operator list, I assume that you just went around the unit boundary and --

A. Yes.

Q. -- and looked for those operators --

A. Yes.

Q. -- immediately offset?

A. Yes.

Q. Are you satisfied that you adequately and completely found the list of those offset operators?

A. Yes. Again, some of the names will have changed from the plat. Keep in mind, the plat on the front is several years old.

Q. Have you spoken to anyone at the Bureau of Land Management about your proposal?

A. I have not, not. Again, our technical representatives have had discussions, our geologist, and he will speak more to this during his testimony.

EXAMINER CATANACH: Any other questions of this witness?

Mr. Chavez?

MR. CHAVEZ: Mr. Klein, I'm Frank Chavez of the Aztec Office --

THE WITNESS: Yes.

MR. CHAVEZ: -- of the OCD.

EXAMINATION

BY MR. CHAVEZ:

Q. In counting the development of the 320-acre tracts within the unit, I count that there -- 29 of the 96 320s are not infilled yet. Do you know if Conoco intends to continue development within those that are not yet infilled?

A. I would like to defer that to our technical representatives, as to any possible plans for infill development in the Dakota, if that would be possible.

Q. I'm curious about Section 8 in Township 27-7, the Number 109 was drilled, and you said it was noncommercial under the -- or could not be included in the unit, participating unit; is that correct?

A. Let me see here. Oh, okay, I see. Right --

Q. Was the west 320 -- I'm presuming the west 320 of Section 8 was dedicated to that well?

A. Yes, it was. This occurred, again, back in 1959. My understanding, the way it should have worked back then was, the entire 320 would have been excluded from the participating area, would not have been allowed to have been brought in.

At a later date, when the 109M was drilled, the way these units typically work is that the lands immediately surrounding the infill would be brought into the participating area, but that the lands immediately surrounding the previous noncommercial well are still excluded, until a maybe replacement well or something is drilled next to the 109, if that were to ever happen, and if it were to be deemed commercial, then those lands would be brought in.

Q. So the west half of Section 8 is dedicated to both wells; is that correct? Both wells -- But however, the production from both wells does not participate in the unit?

A. Right. Well, what happens is, the 109 would be produced on a drillblock basis. The working interest owners within that 160 acres would be allocated the full production from that well. The gas from that 109, in essence, would not be pooled with the gas from the other wells within the Dakota participating area. It's kept track of separately.

Did I answer your question?

Q. Well, what I'm getting at is that it appears that well may not be in compliance with the spacing regulations if the entire 320 is supposed to be dedicated to production from both wells, the drill tract is 320 acres --

A. Right.

Q. -- not 160 in the Dakota.

A. I would have to get back with you on that. I'm not -- I can't speak to that right now. This is something that was done many decades ago. But I can sure research that.

MR. CHAVEZ: Okay, thank you.

EXAMINER CATANACH: This witness may be excused.

MR. KELLAHIN: Our next witness is Mr. Tom Johnson. Mr. Johnson is a geologist.

THOMAS B. JOHNSON,

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. Johnson, would you please state your name and occupation?

A. My name is Tom Johnson, I'm a geologist with Conoco.

Q. And where do you reside, sir?

A. In Midland, Texas.

Q. On prior occasions have you testified as Conoco's geologist concerning the geology of the San Juan 28 and 7 Unit?

A. Yes, I have.

Q. And you did so on prior occasions involving analyzing that reservoir for purposes of the downhole commingling procedures of the Division?

A. That's correct.

Q. As part of your continuing involvement as Conoco's geologist assigned to this unit, have you continued to make a study of the reservoir, particularly the Dakota?

A. Yes, I have.

MR. KELLAHIN: We tender Mr. Johnson as an expert geologist.

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Kellahin) Let me direct your attention, sir, to what is marked as Conoco Exhibit 8. Would you identify that for us?

A. Yes, that's the plat that shows the outline of the 28-7 Unit, which covers all of 28 North, 7 West, and part of 27 North, 7 West. The dots on the map in red show the location of existing Dakota wells, and the green dots are the location of existing Mesaverde wells.

There are several dots on there -- you'll see them in Section 16, the southwest of 16, southeast of 15, the southwest of 20, northwest of 27, the southeast of 34 and the northwest of 36, the dot within the dot. Those indicate the locations of our pilot Dakota wells.

Q. If the Examiner desires to use a plat for reference as to the current location of both the Dakota and Mesaverde wells, would it be appropriate to use this display for that purpose?

A. Yes, it would.

Q. Let's turn to the next display. Identify and describe for us Conoco Exhibit 9.

A. That map shows the same area, it shows the outline of the 28-7 Unit, and again in this case it shows only the Dakota wells. The Mesaverde wells have been eliminated to get rid of some of the clutter. And again, it shows the location of the pilot wells that we wish to drill.

Q. Okay. When we look at Exhibit 9, the well density of the infill wells in the Dakota is substantially infilled to the north and east of the unit, while to the south and west, while the parent or original well has been drilled, there are a number of instances where the infilled well has not. Is there a technical explanation as to why the development at this stage appears in this fashion?

A. Yeah, to the northeast part of the 28-7 Unit, you've got good, consistent development in all different members of the Dakota sandstone. There are -- It's broken up into different units, noted as the Twowells, the Paguate, the Cubero, Oak Canyon sandstones. Those are fairly consistently developed in the northeast part of the unit.

That character does change somewhat as you move to the southwest across the unit, you start to lose some of the development of the Twowell sandstone, the reservoir is not quite as well developed in that part.

Additionally, the Mesaverde is not quite as well developed in that part of the unit, and in years past often Mesaverde and Dakota were both targets, and there just wasn't as much drilling.

For those two reasons, we see less development in the Dakota.

Q. When you testified before Examiner Catanach back in 1995 for the approval of certain commingled wellbores, your opinion then was that the future for the unit was the drilling of commingled wells for Dakota and Mesaverde?

A. That's correct.

Q. Is that still your opinion?

A. Yes, it is.

Q. In your prior testimony, you characterized the Dakota as a continuous reservoir but of very tight, low permeability. Is that still your testimony?

A. That's still my testimony.

Q. Based upon your geologic investigation of the unit and the Dakota formation, what is your geologic opinion about the suitability of the unit for establishing a pilot project to determine increased well density in the Dakota?

A. We like it for several reasons. First of all, as you mentioned, it is a very tight unit. The permeabilities that we see here are on the order of -- in the hundredths of millidarcies, as opposed to tenths of millidarcies for the Mesaverde.

We see -- When we look at pressures in the unit, pressure drop per year, we see a low pressure drop per year over most of the units, with some areas that do show a little bit higher pressure drop. But overall, a very tight -- tight reservoir, low porosity, low permeability.

One of the things that we do like about the 28-7 Unit is that we have the Mesaverde stacked on the Dakota, and when we drill pilot wells, or any wells in the future for the Dakota, we will have the ability to also add the Mesaverde into that wellbore and kill two birds with one stone.

Q. Let's refresh the Examiner's recollections about the orientation of the various producing formations in the San Juan Basin. If you'll turn to the schematic, Exhibit 10, identify that for us and show us what you are talking about when you target the Basin-Dakota Pool.

A. Yes, this is a strat section that shows the entire Cretaceous interval out in the San Juan Basin, and you'll see near the center of the map the Cliffhouse, Menefee and Point Lookout sandstones of the Mesaverde formation.

And then dropping down below the long blue line that extends all across the strat column, the Greenhorn, below that, the Graneros shales and then the Dakota sandstones, the different members. I mentioned the Twowells, the Paguate, the Cubero, Oak Canyon sandstones.

Those are found at a depth of around 7500 feet, the Mesaverde average depth of around 5500 feet. So about 2000, 2500 difference between the zones.

Q. So when we talked about a pilot project in the Dakota, you're identifying the Dakota collectively to consist of all these members?

A. Yes, I am, the Twowells, the Paguate, the Cubero, Oak Canyon sands.

Q. Above that in the Mesaverde group, when we talk about the Mesaverde, what are we talking about as the top and the bottom of the Mesaverde group?

A. When I refer to the Mesaverde, I'm referring to the Cliffhouse, the Menefee and the Point Lookout members of the Mesaverde.

Q. We're going to show Mr. Catanach a structure map in a moment. Show us on Exhibit 10 where that structural marker is.

A. The long green -- the long blue line that cuts across indicates the Greenhorn limestone member. The base of that, the shale between that limestone and the underlying pay sands of the Dakota is the Graneros shale, and that is the marker on which the structure map was built.

Q. You made reference earlier to the fact that Conoco's engineers had examined, studied and prepared a p.s.i.-per-year pressure-drop map.

A. That's correct.

Q. Have the engineers provided you a copy of that map and are you familiar with it?

A. Yes, they have, and yes, I am.

Q. Let's turn your attention to that map. It's marked as Conoco Exhibit 11. In Burlington's testimony before the Division to receive approval for one of their early pilot projects in the Mesaverde, they referred to a p.s.i.-per-year-drop pressure drop, did they not?

A. Yes, they did.

Q. To the best of your knowledge, is this a similar-type map prepared for the Dakota formation within the San Juan 28 and 7 Unit?

A. Yes, it is, the same methodology that was used to build that map was also used to build this map.

Q. The methodology was to take the pressure data from the original well, then compare it to the pressure data available for the infill well and see how many pounds of pressure per year drop there was between the two?

A. That's correct.

Q. Tell us how to read the color code.

A. The color code, there's a scale on the bottom there. The lighter colors in yellow indicate a low p.s.i. drop per year, getting progressively higher until you get into the greens which indicate there is a high pressure drop per year.

Q. Based upon your geologic studies, Mr. Johnson, is there an explanation for the fact that in a small portion of the unit to the south and east, within that area of pressure drop in the range of 50 to 55 pounds per year, is there a geologic explanation to explain why that has occurred there and nowhere else in the unit?

A. Looking at that, everything else being equal, as I mentioned before, the reservoirs appear to be fairly uniformly developed in the northeast portion of the unit. Structure doesn't appear to be a factor out here. The matrix porosity and permeability don't appear to be a factor.

The reservoir is fairly consistently developed, and what I fall back on to explain that is that it has to be an area of a more well developed naturally occurring fracture network.

Q. Let's turn to some of your other exhibits. Let's look at the Exhibit Number 12. What are you showing here?

A. Again, Exhibit 12 shows the outline of the 28-7 Unit, and it shows cumulative production from *Dwight's* from the Dakota sandstone reservoirs. The dark colors on the map -- only Dakota wells are shown on this map again. The darker colors indicate higher cumulative recoveries, with the darker reds showing areas where 2-BCF-plus has been recovered on a per-well basis.

Q. Do you have a geologic explanation as to why there are scattered areas within the unit that have experienced higher cumulative gas recoveries than other areas?

A. Well, if you refer back to Exhibit 11, particularly where you have the p.s.i.-drop-per year map, you'll see that there's an area that extends down to the southeast outside the unit that does show a little bit higher recovery, and I would attribute that, at least in part, or maybe in large part, to the fact that we have a better naturally occurring fracture network in that area.

Some of the other variations you'll see in the map, on a cumulative production basis, we've been very active in drilling a lot of wells out here in the last three years, and some of the lighter yellow-colored areas just haven't had time to cum as much gas.

Q. Let me have you direct your attention to Exhibit 13, and identify and describe that display.

A. Exhibit 13 covers the same area again. It shows Dakota wells, and it shows the 1998 daily rates. And once again, you can see down in that same area where you have the higher pressure drop per year, you're seeing some darker red colors indicating higher cumulative recovery on a per-well basis.

And once again, there are areas in the map, since we have been busy drilling wells, that are just the opposite from the cum map. They haven't on long, so they haven't cum'd much and they show light colors. But on the other hand, they're fairly new wells, so they still produce at relatively high rates. You see some trends of high production where we have drilled new wells.

Q. You made reference earlier to your opinion that structure does not play a significant role in determining the productivity of areas in the Dakota within the unit?

A. That's correct.

Q. Let's look at the display that illustrates that. If you'll turn to Exhibit 14, identify and describe that.

A. That is a structure map that was built on the base of the Greenhorn, top of the Graneros shales. I previously described on this column, Exhibit 10, and what that shows is regional dip getting deeper to the northeast, where the colors get lighter.

The depths listed by each well are in subsea depths. They're below sea level, so they get more negative to the northeast, indicating that we're getting deeper.

The map doesn't show any major structural features, any major faulting, any major rollovers, anticlines or synclines. It just shows regional dip to the northeast.

And the same regional dip is seen as you move upsection on the map at any horizon, it will show basically the same thing.

Q. Let's look at the continuity of the reservoir, and to do that, if you'll identify the cross-section locator map, Exhibit 15, then we'll show the Examiner the cross-section.

A. Once again, this map shows the outline of the 28-7 unit. It shows all Dakota wells that have been drilled to date. It shows our proposed pilot locations, and it indexes cross-section D'-D, which runs from the northeast corner of the unit all the way down to the southern portion of the unit.

This cross-section -- The stratigraphic cross-section goes to show the Dakota sandstones, 14-well cross-section.

Q. Summarize for us the geologic conclusions that you reach, based upon your study of the stratigraphic cross-section.

A. We're referring to Section 16?

Q. Exhibit 16?

A. Yes. You see the datum of the cross-section, again, D-D', D to the northeast, running to the southwest, covering the whole unit. It's on the top of the Greenhorn limestone, and you can see the labels on the right-hand side.

You can see the Graneros, which I referred to previously, at the base of the Greenhorn, on which the structure map was built.

Then you'll see -- The first cleanup that you'll see down below that, the first sandstone that you get resistivity kick to the right, generally indicative of the pay zones in the Dakota, is the Twowells sandstone. If you follow that Twowells sandstone across the unit, follow it to the left on your cross-section, you'll see that that sandstone is fairly consistently developed, as you move across the unit, till you get about halfway down. And as you move across, you start to see some deterioration in that sand development.

The next sand down is the Paguate sandstone, and that is very consistently developed across the unit. It's between 20 and 25 feet every place you look at it, and you can follow that from stem to stern across the whole cross-section and see it developed about the same.

And finally the Cubero Oak Canyon sandstone below the Paguate. They're a little bit more laterally discontinuous in their development. Generally, you pick up about between 30 and 35 feet of pay sands in that interval. There's some variability in what you see in that horizon, simply because many of the wells in the unit are drilled on air, and operators try not to drill too deep, because you eventually will encounter water below the Dakota.

Q. Collectively, when you look at all the geologic information that you have analyzed and studied, is the fact that the engineers can calculate a pressure drop per year a good indication of effective permeability in the Dakota?

A. Yes, it is.
Q. And to what do you attribute that permeability?
A. Just the very tight matrix permeability in the Dakota sandstones. They're fine to -- very fine to fine-grained quartz sandstone. The primary permeability in there is very low. Again, it's on the order of .01 of a millidarcy, .02 of a millidarcy permeability. And without a nice natural fracture network, it's just very tight rock.
Q. The differences, then, in rates of pressure drop are attributed to your opinion that there's natural fracturing in the Dakota?
A. Yes, sir.
Q. It is not explained by an examination of structure or reservoir thickness?
A. No, reservoir thickness, structure, matrix porosity, permeability, those things don't explain the variation that we see, and I would attribute that to natural fracture development in the unit, in the Dakota sandstones.
Q. Is it geologically consistent with your opinions that this is a tight, low-permeability reservoir, when the engineers tell you that they have these low pressure drops per year?
A. Yes, it is.
Q. In your opinion as a geologist, is it appropriate

to conduct an infill pilot project, as proposed by Conoco, in order to gather additional data for determining well density in the pool?

A. Yes, it is.

Q. Are these locations acceptable to you as a geologist?

A. Yeah, they are.

Q. Will these be suitable locations, geologically, for you to gather additional data to determine the appropriate well density in the unit as well as the pool?

A. Yes, they should be. We picked locations that covered a -- represented a good geographical spread across the top of the unit. We tried to place the wells in locations where there was development in the -- currently in the 160, there are several 160s undeveloped in the Dakota in the northeast part of the unit.

We wanted to avoid those and put it in a position where there was development in the Dakota all around it, at the same time keeping in mind, where the Mesaverde was currently developed, that there weren't any Mesaverde single wells in the area, and try to keep as far away from existing wells as we could, to get a fair test of the concept in these pilot wells.

MR. KELLAHIN: Mr. Examiner, that concludes my examination of Mr. Johnson.

We move the introduction of his Exhibits 8 through 15.

EXAMINER CATANACH: Exhibits 8 through 15 will be admitted as evidence.

Mr. Cavin, did you have any questions?

MR. CAVIN: Yes, Mr. Johnson, I just have a few questions.

EXAMINATION

BY MR. CAVIN:

Q. Can you tell me where the Chacra formation is in relation to the Mesaverde?

A. Yes, the Chacra is actually -- It's another member of the Mesaverde, and it -- I don't see it labeled on here, but if you'll look right above the Cliffhouse up on your strat column, there's a little star right by the Cliffhouse.

Q. Yes.

A. And right up above there you see some yellow sand with another well symbol on it, and that would be the approximate position of the Chacra sandstone. It is a Mesaverde sandstone unit, not a Dakota sandstone unit.

Q. Great. Can you tell me in these -- What's the estimated productive life of these wells you're proposing?

A. These are very long-lived. We've got wells -- The earliest Dakota wells were drilled in the 1950s and are still producing today, so these are 30-year-plus wells.

Q. Okay. Is there potential in the shallower zones of Pictured Cliffs and the Fruitland in these wells also, is that --

A. There would ultimately be in these wells, but we're drilling these wells to gather data for -- first of all, to justify the pilot wells in the Dakota, and we eventually plan to, after gathering sufficient data, go ahead and complete the Mesaverde. And I don't think that we would utilize these particular wellbores at any point in the near future to produce anything other than Mesaverde and Dakota.

MR. CAVIN: Thank you.

EXAMINATION

BY EXAMINER CATANACH:

Q. With regards to the infill wells in the southwest part of the unit, your testimony is that as you move towards that area in the Dakota, some of the formations deteriorate or --

A. Yeah, you don't see the Twowell sandstone developed quite as well. I know in all the drills we do in the northeast that there's enough sandstone up there and good enough development in the Twowells where it merits a separate fracture stimulation.

When we move down to the southwest part of the unit, there's still gas in those Dakota sands, and if you can put Mesaverde and Dakota together, especially in the far southwest portion of the unit, you can get economic gas out of it, but the reservoir is not as well developed in the southwest part of the unit as it is in the northeast, both in the Mesaverde and the Dakota.

Q. Does Conoco have plans to continue developing the southwest part of the unit?

A. Yeah, we currently have plans to -- We had a drilling program going this year. We still have two more wells to drill on that part of the unit, Mesaverde and Dakota, in the southwesternmost portion of the unit.

There's the gap -- as you come along, roughly where -- in Section 15 where the unit makes a bend there, if you strike a line going due northwest across the unit, that point northeast, you've got pretty fair development in both Mesaverde and Dakota reservoirs.

Then there's kind of a gap where both the Mesaverde and Dakota are very poor, particularly the Mesaverde. You lose the Cliffhouse and you lose the Point Lookout.

In the extreme southwest corner of the unit you have a nice Point Lookout bench which extends on down from the 28-7 unit, way down into the Jicarilla tribal properties in the southeast portion of the Basin, and that's really the development that allows us to drill Mesaverde and Dakota wells in the southwestern portion of the unit.

Q. The differences in the pressure-drop areas throughout the unit, do you attribute that to the existence of fractures in some areas?

A. Yes, I think that probably primarily is attributable to fractures, knowing that the structure is not causing it.

Say that if it's on -- affecting where the naturally occurring fracture is developing, any subtleties in structure, and it's not due to reservoir thickness, because there's no apparent correlation between how thick the sands are in this northeast portion.

You see some variability, and that doesn't really seem to affect the kind of rates we see out of the Dakota. Where I see that higher pressure drop per year and any associated better production I would attribute it to natural fractures, yes.

Q. It's not, in your opinion, attributable to differences in permeability within those wells?

A. I think -- Not primary permeability, I think it's fracture-enhanced permeability. It's not the matrix permeability and porosity that's causing that. I think it's fracture-enhanced.

Q. Okay, did you look at that? Did you look at the primary permeability?

A. We have -- The permeability data that we have in the unit is derived -- We have no core in the unit. It's derived from pressure buildups that we've taken and from core data that we have all around the unit, and also from prior work that's been done as far as Fetkovitch type-curve matching.

And all that data all shows very, very low permeability, again on the order of .01 of a millidarcy permeability, an order of magnitude lower than what we see in the Mesaverde.

Q. Were you involved in actually determining the well locations?

A. Yes, I helped select those.

Q. And was there a geologic factor used in that?

A. Well, we wanted to get, first, a good geographic spread across the northern portion of the unit, and we wanted to be in areas where there was currently development on a 160 basis, so we would be giving it a fair test in the pressure that we would encounter there. We want to get good pressure data at these locations and not go into areas where we only have -- where we might have 160-acre location that's open.

Also, taking into consideration topographic limitations, we might have archaeological considerations that we might have in structure, access, existing roads, and the desire to eventually come back and commingle these wells with the Mesaverde, were all factors in determining these locations.

Primarily, we selected these locations to get a fair spread in relationship to the pressure-drop map and a fair spread across the northern portion of the unit where we anticipate the bulk of the activity to occur in the future.

Q. It doesn't sound like there was a geologic factor involved in that determination.

A. Well, it was just to confirm -- Really, I expect no geologic surprises out here. As I've looked across the unit, everything is fairly consistent in this development. I don't expect to see any major structures, any major faulting, or anything other than what I see on every other well that's drilled around it. We've got a lot of well control out here.

Q. Did you guys get a good representative sample of -- Did you place wells in areas of different pressure drops or --

A. Yeah. We don't have them quite in the highest pressure drop areas, but if you refer back to Exhibit 11, you can see that that kind of runs the gamut and approaches the darker colors with higher pressure drop and also in the yellow areas that show a lower pressure drop.

EXAMINER CATANACH: That's it.

Mr. Chavez?

EXAMINATION

BY MR. CHAVEZ:

Q. You stated you didn't expect to have any geologic surprises on this. Will you be doing anything special to gather any new geologic information besides running logs on these wells?

A. We hadn't anticipated collecting any core data. To get any viable perm data, rotary sidewall cores really don't do the job. It gives you some data, but it only gives you horizontal perm. It doesn't give you vertical perm as well.

What we plan to do to gather data to confirm the permeability is to run pressure buildup data in these new wells, to go ahead and complete and just clean them up and then shut them in for an extended -- possibly a 30-day pressure buildup. And from that we can gather the perm data that we need, and not go to the additional expense of having to core these wells.

Q. Will that testing be a little more complex, for example, testing each of the sands you delineated as part of the Dakota, or just the entire interval?

A. I think we would probably test the entire interval. A lot of these sandstones are fairly close together, and I don't know that we would be able to get separate tests. We may be able to get separate tests should engineering determine that that's really needed to be done.

But at this point in time I think the plan is to get a pressure buildup on the Dakota sands as they'll be produced, all as one package, all as one package of sands put together.

MR. CHAVEZ: Thank you.

FURTHER EXAMINATION

BY EXAMINER CATANACH:

Q. Typically, you're not going to have -- if you don't have fracturing in one of the sands, you're not going to have them in the other two; is that a fair statement?

A. I would anticipate that the fracturing probably would -- These sands are all very close together, and I would expect that if there's a good fracture in one sand, you probably would see it in all sands. That might not necessarily be the case, but it would seem logical to me that you would see that fracturing in all the zones.

EXAMINER CATANACH: Okay, I have nothing further of this witness.

Mr. Kellahin, any other questions of this witness?

MR. KELLAHIN: no, sir.

Mr. Examiner, Mr. Soni is an expert in reservoir simulation, and he is our next presenter. His exhibits are before you, and we will go through his experience and expertise, and then he'll show you how Conoco has simulated a portion of the unit and what that has shown.

YOGENDRA SONI,

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, sir, would you please state your name and occupation?

A. Yogi Soni, and I am a chemical engineer by education and a petroleum engineer by practice.

Q. Mr. Soni, how long have you been involved with Conoco's simulation activities?

A. For the last 19 years.

Q. Nineteen years?

A. Yes.

Q. Where do you reside?

A. In Katy, Texas.

Q. As part of reservoir simulation for Conoco, have you studied the simulation --

A. Yes, sir.

Q. -- and been involved in the simulation of a portion of the San Juan 28 and 7 Unit?

A. Yes, sir.

Q. And as a result of that work, do you now have conclusions and opinions concerning --

A. Yes, sir, at this stage we have two major conclusions. One is that 80-acre infill wells will produce about 700 million cubic feet gas.

And there are two sensitive parameters that we rated, and based on that, we believe the range of additional results will be somewhere between 500 to 800 million, depending on what the reservoir permeability and initial gas in place is.

MR. KELLAHIN: Mr. Examiner, we tender Mr. Soni as an expert in reservoir simulation.

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Kellahin) Let's talk about the conclusions again. When you talk about the simulation, the model has been calibrated so that you can determine what would happen in a 320-acre spacing unit if you introduced a well density of four wells per gas spacing unit?

A. Yes, sir.

Q. And based upon that activity, the simulation results show that additional gas --

A. Yes.

Q. -- not otherwise recovered by any of the infill or parent wells would be in the neighborhood of 704 million MCF?

A. Yes, sir.

Q. In addition, the analysis by simulation has been run using various sensitivities?

A. Yes, sir.

Q. And the sensitivities were various ranges of gas in place?

A. Yes.

Q. And various ranges of permeability?

A. Yes.

Q. And using both those ranges you can demonstrate with increased density --

A. Yes, sir.

Q. -- that up to four wells per GPU would have a range of recovery shown under the second conclusion?

A. Yes, sir.

Q. Okay. And then finally, your simulation results were used by Mr. Mark Shannon, the last witness, to talk about the economic consequences of the activity?

A. Yes, sir.

Q. All right. Let's go to the subject of where the simulation modeled the unit. You're in what portion of the unit, Mr. Soni?

A. We picked up Section 36, because it is a typical section and does not have an unusual pressure drop, and we have some pressure data in this section.

Q. Is it important to you to have additional bottomhole pressure information, other than what has historically been compiled on an annual basis for Dakota wells?

A. Absolutely, yes, sir.

Q. And one of the few data points you had in the unit was your well in Section 36?

A. Yes, there were two wells in Section 36 which were originally drilled on 320-acre spacing, and we matched the performance of those wells.

MR. KELLAHIN: Mr. Examiner, when I handed out the exhibits, I gave you separately a colored copy of Exhibit 18, and if you'll replace the color copy with the photocopy, Mr. Soni and I will have him describe the grid and how the simulation was handled in terms of the well.

If you'll turn to Exhibit 18, Mr. Soni, let me give you a better copy.

THE WITNESS: Thank you, sir.

Q. (By Mr. Kellahin) For purposes of this presentation, the simulation was to model the performance of what you characterized as a typical 320-acre spacing unit?

A. Yes, sir.

Q. If I look at the grid area contained on Exhibit 18, that is in the shape of a rectangle, the blue area --

A. Yes, sir.

Q. -- does that correlate to a 320-acre spacing unit?

A. Yes, sir, the 320-acre well is the yellow square which is split into three parts, a quarter well at the top right-hand corner, a half well in the middle, and a quarter well in the bottom right-hand corner. Together they add up to one well, which is 320 acres.

Q. This, in essence, would be a snapshot of a portion of the pool where you're assuming for purposes of simulation that there are competing Dakota wells all around the modeled grid, right?

A. Exactly, and that's the reason for choosing this kind of a grid and spacing.

Q. Is this acceptable methodology for reservoir simulation?

A. This is done all the time. We do symmetry elements and use that as a basis for a large field.

Q. With the introduction of the original wells being the yellow squares, the computer assumes that there is a no-flow boundary created in certain directions; is that not true?

A. Yes, sir.

Q. Describe for us what the simulation will assume in terms of no-flow boundaries.

A. In a field such as this, where wells came in at different points in time, the best no-flow boundary is the one going right through the wells, and this model shows that, that all the boundaries are going right through the wells, and that's why they are no-flow boundaries.

Q. Also on the boundaries of the grid are some yellow circles?

A. Yes, sir.

Q. What do those represent?

A. They, together, will represent the infill 160-acre well. Again on the right-hand top -- left-hand top corner, is quarter well, in the middle is half well, and at the bottom is a quarter well. Together, they add up to one single 160-acre well.

Q. With the introduction of the infill well, then you also are able to introduce what we've called the increased density wells, and how are those identified?

A. And these are the green squares which now represent the 80-acre wells.

Q. All right.

A. I might add, the reason for choosing this kind of grid is that you maintain the symmetry as well as you maintain the spacing.

Q. Exhibit 10 makes reference to the log analysis performed by Mr. Johnson, and the footnote on the bottom simply refers to the fact that the simulation could also be performed on the Mesaverde --

A. Yes, sir.

Q. -- but the input parameters for purposes of this presentation are limited to the Dakota, are they not?

A. That is right.

Q. Was all this work done and the methodology chosen in a manner acceptable to you as an expert simulator?

A. Yes, sir.

Q. Were you satisfied that there were appropriate data points that were reliable for introduction into the simulation?

A. Yes, we used all the data that we have up to this point.

Q. To the best of your knowledge, are the conclusions you've arrived at based upon accurate, reasonable work product from this type of simulation?

A. Yes, sir.

Q. Let's turn to the details of the simulation now, Mr. Soni. If you'll turn to Exhibit 19, summarize for us what you've done.

A. The model is constructed in grid form, 64 by 89 aerial grids in three layers. As Tom had described, we have three sands, so each sand was one layer in the model. And we used the data from the logs to input into the model. The grid is tilted by 2 degrees, which reflects the regional anisotropy.

Q. All right, then the model area, as we've described, is a typical 320-acre spacing unit --

A. Yes, sir.

Q. -- using the data you had?

Exhibit 20, identify and describe what you're showing here.

A. Here I'm showing the layer properties. The thickness, as noted here, is the net thickness, which is the gross thickness times the net-to-gross ratio. And again, these have come from the log analysis.

Porosity is considered uniform at 8 percent in all the layers, and the initial water saturation is set at 35 percent. And these properties -- What I'm not showing here is the permeability because we varied that, and I'll refer to that later on.

Q. Mr. Soni, in prior presentations concerning the Mesaverde reservoir, Mr. Catanach has been presented by Burlington geostatistic and stochastic modeling geologic information that went into their reservoir simulation. Are you familiar with that methodology?

A. Yes, sir, I've used it in the past several times.

Q. In your opinion, is it appropriate or necessary to use that type of information or modeling technique to examine well densities in the Dakota?

A. Not at this stage, no sir, because we are testing a typical pattern and typical response, so right now it's too early to do any stochastic modeling. We will do that for a full-field modeling, and also we have done that in reservoirs where well spacing is very sparse and we really don't know what happens between the wells.

Here we have a lot of wells, and stochastic modeling will be right now a little bit inappropriate.

Q. Stochastic modeling would not give you any more sophistication in your efforts than you can derive from looking at 155 logs in the unit that already exist for the Dakota?

A. Absolutely. And I might add, the best stochastic models, they really try to honor the well data and fill up the spacing between.

But if you have lots of wells like we have here, then the model is bound, and it's not going to do any more than what you can do simply by drawing the cross-sections.

Q. Let's talk about how you've calibrated the model. If you'll turn to Exhibit 21, describe for us what you've done.

A. Yes, here you see the actual response from the two wells in that Section 36, and then the green line shows the model response. The initial rate was adjusted by the skin factor, and the drop and the decline was adjusted by gas in place. We do not know the exact gas in place by any direct measurement, so this is an indirect way of confirming that that gas in place is consistent with the performance.

Q. Is it characteristic of a typical Dakota decline curve to see the early time decline on a sharp basis and then later have that decline arrested and the gradual decline depicted as you've shown?

A. Yes, sir, it is exactly the same characteristic.

Q. Are you satisfied that you've accurately calibrated the model, consistent with the available data within the modeled area?

A. Yes, sir.

Q. All right, let's turn to the specifics of the calibration, if you'll identify and describe Exhibit 22.

A. What you saw earlier was a decline rate, but also we have declined a few points in that, both for 320-acre well and the infill 160. We have honored the cumulative production to date for both these wells, which is .95 and .89 BCF, the current production rate, which is 70 MCF and

75, and the model predicts the ultimate recovery that we know from these infill wells.

Q. All right, sir, and let's talk about the prediction. If you'll turn to Exhibit 23, describe for us the assumptions you've made in the model in terms of ultimate prediction.

A. Yes, we have set some ground rules for prediction. One of them is that we are carrying the model up to generally 1-2030 -- I think that's long enough -- and beyond that, whatever little recovery we get has very little impact on the economics.

The limiting bottomhole -- flowing bottomhole pressure, is set at -- it drops by 50 p.s.i. every ten years. That is to reflect the drop in reservoir pressure.

Wells are set to an economic limit of 25 MCF per day, and beyond that the simulator would automatically shut them.

The 320-acre well in the model came on April 1, 1975, and the infill well, bulk of them, were drilled in the late 1970s and early 1980s. The infill well comes in at the end of 1979.

We propose to put the 80-acre infill well somewhere in this year, 1999.

So these were the ground rules that were used in the model.

Q. Once you've satisfied yourself that you've got accurate data in your model, that it has been properly calibrated and history-matched to the performance of those two wells, and you've set these ground-rule assumptions, then you allow the model to run and to arrive at some forecasted conclusions?

A. Yes, sir.

Q. Let's turn to Exhibit 24 and see what the model forecast.

A. Okay. In this diagram, you see the black line. That is the cumulative production from a 320-acre well with no infill well at all. And as I have pointed out earlier, that has been history matched up to this point, so we are very confident that the predictions there are really reliable.

Now we turn to the stars, which is the 160-acre well. Again we have history-matched that, and those predictions are reliable.

Having matched those two curves, now we are confident that at least geologically the model represents the 80 we are modeling, so the green line is what you see at an 80-acre infill, and the wedge between the green line and the stars is the additional gas that we'll recover. It's not the accelerated, but it's the net additional gas.

Q. There's a difference, a significant difference.

So what you're talking about when you say additional gas, you're defining what the increased-density well will recover, that would not otherwise be recovered by the original well or the infill well?

A. Yes, sir.

Q. Let's total those numbers. If you'll turn to Exhibit 25, what are the numbers?

A. If we look at the simulation run, you'll find that the 80-acre single well will produce 829 million cubic feet. But out of that, 125 came by robbing the other wells of their rate, so 125 would have been produced by other wells without the 80-acre.

But the next, 704 million cubic feet, is the additional reserve that would have been unrecovered.

Q. After obtaining those conclusions and results, then did you adjust certain parameters to see what would happen under a different set of circumstances?

A. Yes, sir.

Q. And the first circumstance that you adjusted for was the possible range of permeability?

A. Yes, sir.

Q. Let's look at Exhibit 26 and show what ranges of permeability you introduced into your simulation.

A. In the model we used .01 millidarcy, which has come from the earlier pressure buildup tests, and then we used a permeability which is half of that and one which is three times that.

Same goes for the initial gas in place. Our model history match is based on 21 BCF per section, and we again tested what happens if there's less gas or more gas in place.

I might add that these sensitivities -- Even though we have history-matched only the best case, these sensitivities will be a consistent way to find out what happens if permeability or gas in place the way it is.

Q. Let's look at the various results of changing these components. If you'll start with Exhibit 27, you're modeling what you call low permeability. What is the number you used?

A. Yeah, this is the one with .005 millidarcy, and you see the same three colors in the same orientation. The black is 320-acre alone, the stars are 160-acre infill, and green is the 80 acre.

I must add that this time it is not history match because this is not a best case. This is just the sensitivity that we are doing by changing the permeability.

One more word of caution is that the scale is different, so do not simply go by the lines and how far apart they are. It's different scales. So best is to look at an exhibit that will come later which summarizes the response.

Q. Let's look at Exhibit 28. When you're modeling a sensitivity for a high permeability, what is the actual number used by the model?

A. Here we are using three times the best case, .03 millidarcy. And again that wedge between the green line and the stars is our additional recovery.

Q. And again, the scale is going to be different between Exhibits 27 and 28?

A. Yes, this time the scale is almost -- more than a factor of two.

Q. Let's go to the tabulation of the sensitivity run. If you'll look at 29 where it's summarized, describe us the results from the two different sensitivities.

A. Yes, so in case you have low permeability, we still recover additional reserves of 573 million. And accelerated reserves are much less this time because you've got a tight reservoir; there's nothing to accelerate there.

If you have high permeability, it is agreed that the 160- and 320-acre well will also recover more gas. So the acceleration portion is much higher this time. While the total recovery is 896 million, the accelerated is 316. what we are interested in is the additional reserve, which still is substantial, 580 million.

Q. All right, let's look at the other component that was changed; it was the gas in place. If you'll start your discussion with Exhibit 30, show us what you mean when you identify a high initial gas-in-place number.

A. The gas in place that was used in the model is 25 BCF per section, and that is based on the history match.

Now, in this we simply weighted that to a higher number, which was 25 BCF per section, and the results are seeing here is based on that higher gas-in-place number.

Q. All right, if you'll look at Exhibit 31, you've changed the sensitivity as to the initial gas in place, you've described it as a low initial gas in place. What's the number used here?

A. Yeah, this time we cut the gas in place by a quarter, and we used 15 BCF per section.

Q. All right, let's turn to Exhibit 32 where you've summarized the two sensitivities by changing the initial gas in place. Show us what results you attained.

A. When you have low gas in place, it is lower reserves because there is less gas, and the additional component this time is only 496 million.

For higher gas in place it will be logical to assume that the model will predict higher gas, and we can recover up to 797 million.

The point here is that these numbers are consistent with our best case which was used for the economics, which was 704. So less gas in place, we will recover less additional reserves; more gas, more reserves. But in a consistent manner.

Q. Based upon your reservoir simulation, Mr. Soni, in your opinion, would approval of the pilot project be a reasonable next-step activity to determine the appropriate well density within the unit for Dakota production?

A. Yes, that is a very conservative way of doing it. The model shows that we will get additional reserves.

The only next step logical is to prove that we indeed are right in our model assumptions, which we can do by pilot wells.

Q. Based upon the current study and simulation, in your opinion is there substantial additional gas that could be recovered from the Dakota formation by instituting a pilot infill project?

A. Yes, sir.

MR. KELLAHIN: That concludes my examination of Mr. Soni.

We move the introduction of his Exhibits 16 through 32.

EXAMINER CATANACH: Exhibits 16 through 32 will be admitted as evidence.

Mr. Cavin?

MR. CAVIN: I have no questions.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Soni, later on in this process will you use the stochastic modeling?

A. If we want to do full-field modeling, we probably will give it a try. But based on what I've done, I think the stochastic model will pretty much produce the pictures you can get from the current wells.

The way stochastic model works, it starts from one well, tries to honor what you see, and moves to the next well. If it cannot honor it, it comes back and retries. With so many wells, its hands upon, it will ultimately turn out to be -- and this is my guess -- that it is going to be a simple areal map that a geologist can prepare right now.

I might add, sir, Conoco has been a leader in stochastic modeling for many years, and we have done extensive work on it.

Q. How did you guys -- For the base case model, how did you determine the permeability to use in that?

A. This came from pressure tests, the pressure buildup tests that Tom referred to, .018 or .01, in that range, and that's what we used.

Q. And those were taken on those wells in that 320-acre unit, or is that --

A. I'm not sure. I think there was some pressure data on the wells in that 320-acre, but I defer that question to the next witness.

Q. How did you guys determine what range to test, on the permeability?

A. On the permeability, I think this is a reasonable range of one-half to three times. I think the idea here is to cover enough range so that we can see the effect. It's -- The purpose here is that the range is not coming from some actual data, but just going around the mean and spreading assumptions.

Q. Do you think that's representative of what you may encounter in the unit?

A. Yes, I think that's a fairly good assumption. But what we get out of this study is that it didn't matter too much when we changed the permeability. The additional gas was still in the range of 500 plus.

Q. And the gas in place, how did you guys get that range?

A. The gas in place, we are very confident that what was used in the model is very representative, and anything less or more than that, we are not likely to encounter it, because it will not match the pressure data, though I must say that we are still waiting for some good pressure data.

And gas in place is no surprise again. The higher the gas in place, these wells will be more economical.

Q. That gas-in-place number, is that representative of more the northern and eastern part of the unit, do you think, or --

A. This is my guess. I cannot speak to it.

Q. Now, the 704 million additional recovery, that is per --

A. Per well.

Q. -- per well on 80 acres?

A. Right.

Q. So you should -- If you drill to two infill wells, you'll recover about twice that?

A. Yes, sir.

EXAMINER CATANACH: Okay. Do you have anything, Frank?

EXAMINATION

BY MR. CHAVEZ:

Q. Mr. Soni, I guess I didn't fully understand your explanation of Exhibit 18. It's labeled "Mesa Verde Rock Properties..." and all this. Is this -- You say this is analogous to what you -- Dakota; is that the purpose of this?

A. I think we were cutting corners there. It's part of a report which contains Mesaverde and Dakota, so ignore the writing on it because it just came from a report and we didn't have time to make it ready yet.

The model grid was used for Mesaverde also, which is not part of today's discussion. Same grid was used. So I would ignore all the writing.

Q. All of the writing?

A. All the writing.

Q. Okay, because I --

A. Yes.

Q. Your Exhibit 21, which is the model well calibration, just by physically looking at this, observing the green curve which is from the model, it appears to me that I would expect that if these lines were projected, extrapolated further, that they would continue the same direction, and at the beginning of the early history in time, say before 1000 days, your model is tracking the D226 very well, but in the last days it's only tracking the D222 [*sic*] well, and, if extrapolated further, that your model line would be much higher than the other two lines, and it doesn't seem to appear to go between them, and -- I don't know, is that just -- Is that observation not important?

A. I think if we really work very hard at it, we can really make it go through those two lines, but it's not justified at this stage. But you need to look at model calibration along with the Exhibit 22, which matches the current rate, the current cumulative production. So those are the big numbers that we need to match at this stage.

The amount of data we have at this time, this much calibration is justified.

Q. Okay, so it's not significant at this time?

A. Not at this time.

Q. Your Exhibit Number 24, did I understand you correctly that the model that you have, the green line, is actually showing how it matches the production in the early life of the area or in this model, up until the point where 80-acre density was initiated? Is that matching in there?

A. That is right. The green line really matches the black line, because it is -- up to 1980 there was only one well, 320 acres. After that, the green line tracks what happened when 160-well came in.

But we are interested here what happens beyond 1999, when 80-acre wells comes in.

Q. Okay, so the first part, up until 1999, is matching actual performance?

A. Off 160-acre and 320-acre wells, yes.

Q. Okay, and then from 1999 on, it's a projection?

A. That's right.

Q. Okay. Then if I heard you correctly on your sensitivity graphs, the first part was not matching?

A. That's right.

MR. CHAVEZ: Okay, thanks.

EXAMINER CATANACH: Any other questions of this witness?

This witness may be excused.

MR. KELLAHIN: Mr. Examiner, our last witness is Mark Shannon.

MARK SHANNON,

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

A. My name is Mark Shannon. I'm a staff engineer for Conoco, Inc.

Q. And where do you reside, sir?

A. Midland, Texas.

Q. What has been your involvement in this project to study the possibility of increasing the well density in the Basin-Dakota Pool, using wells in Conoco-operated San Juan 28 and 7 Unit?

A. My involvement has been primarily to evaluate the Dakota pressures from the first wells drilled, plus all of the infill wells, plus working with Mr. Johnson on understanding the geology of the 28-7 Unit, as well as looking at all the rate data, all the production data, and studying a little bit of the prior reservoir engineering studies and this sort of thing. So it's been very much strictly an engineering -- a reservoir and production engineering role.

Q. Was Exhibit 11 that Mr. Johnson referred to, the p.s.i.-per-year-drop pressure map, prepared by you?

A. Yes, sir, it was prepared by me.

Q. Based upon your studies, do you now have engineering opinions and conclusions about the appropriateness of obtaining Division approval for a pilot project to study the increased density in the Dakota?

A. Yes, sir.

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

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Kellahin) Let's take a moment and go back and look at Exhibit 11. Describe for us what this means to you as an engineer.

A. There's two or three things that ought to be pointed out. First and foremost, obviously, there's various very large areas of the unit where we're seeing pressure drops from zero to 20 to 25 p.s.i. And then in other areas, say 20 percent of the unit or even less, where the pressure drops are quite a bit more.

So one very obvious thing is, there's a lot of variation across the unit in terms of the pressure drop.

Also, we've looked at every infill well plus every parent well to try to understand the asset, and what the pressures are doing out here. And it's a very similar methodology than what Burlington did last year, or two years ago, when they did the 29-7 pilot.

But what really stands out to me is just the variation across the unit in a fairly small area as to how much pressure drop there has been.

Q. Let's set that map aside for a moment and look at your Exhibit 33 --

A. Okay.

Q. -- where you have summarized the pressure history, if you will, of the Dakota within the unit.

Give us a short chronology of what's occurring here on this display.

A. Okay, what I've done here is just build on this pressure map a little bit. Arbitrarily, I broke out the pressure history over four events, pre-1970s, 1970s, 1980s and the 1990s. And two or three things I draw your attention to.

Number one, we really didn't see any pressure depletion at all until the 160-acre infill wells were drilled. And in fact, it wasn't until the 1990s that we saw any significant -- or what I'm calling significant pressure drop.

If you look at the 1990s line, you can see 1700 to 2800 p.s.i. That's actually based on the pressure buildup data that we have from last year, and we'll get into that in just a second. But it's just to build on the data that you've already seen, and again, following kind of the Burlington convention on calculating pressure drops across the unit.

Q. Let's look at Exhibit 34. You made references to the pressure buildup history. For how many wells in the San Juan 27 and Unit [*sic*] do you have actual bottomhole pressure tests that are sufficient to be reliable for your purposes?

A. For my purposes there are only three, and those are the three that we did last year. They were 182M, the 226M and 232M, which fortunately were spread across the unit. But those are the three that we have, and that's the data that we used, in part, to build that map.

Again, I'd draw your attention to a couple of things here. One is just the variation in the pressures. You'll note the 182M, for example, had an estimated shut-in bottomhole pressure of 1728 p.s.i., whereas the 226M was 2468 p.s.i. So there's quite a bit of variation right there, just between those two wells.

A couple other points. One is, there's been a lot of discussion here about the permeability. From these tests, I evaluated the permeability to be in the range of somewhere between .01 and .02 millidarcies. That is somewhat substantiated by some of the earlier work that Conoco had done about five years ago with Fetkovitch type-curve matching, which showed an average of .01 to .02 millidarcies, so we have some consistency there in those numbers.

One other point is to note the shut-in time. Two of the wells, we shut the wells in for over 70-some days. So these were not shut-in times; these were very lengthy buildups. So we have some confidence in the accuracy of the data there.

Finally, one last point, the pressure loss, which I guess really gets to the meat of things here. In the case of the 226M and the 232M, we saw roughly 20-percent pressure drop from the original reservoir pressure, which was 3000 pounds, and that's not very much in all the years that we've been producing out there. One exception there being the 182M where we saw some 44-percent pressure drop.

So again, we're seeing a lot of variation in the pressures. But all things considered, the pressure drop hasn't been very much, as you can tell from the map.

Q. When Mr. Soni is matching pressure within his modeled area, which of the three well buildup tests is he using for the modeling purposes?

A. Yes, if you refer back to the pressure map, in Section 36, in the northwest corner, there's the 226M. That was the data point that was used in that reservoir model, was the pressure coming from that one well.

Q. Did you help select the location of the six pilot wells for the infill project?

A. I was involved in that process, yes, and for the reasons that Mr. Johnson testified previously, he didn't know where the locations are and why they were chosen. But I was involved in that.

Q. In terms of gathering reservoir data from an engineering perspective, what do you hope to accomplish with the drilling and testing of these six pilot wells?

A. There's two key pieces of data that would arise from drilling those wells. Number one, we will see rate data as a Dakota single type completion initially, in 80-acre-type locations. Now, we don't have anything like that now, so that's one very important piece of data.

Number two is pressure. We need a little more pressure data, and we've selected these six locations to provide pressure data.

And then from that data, of course, you can infer things such as permeability, skin, the efficiency of our completions and this sort of thing. But those pieces of data we need, rate and pressure.

Q. Is it possible now, without that data, to reach ultimate opinions and conclusions about increasing the well density in the Basin-Dakota Pool?

A. Well, when you say "ultimate", understand, we've only done three wells here, three buildups, and there's thirty-some-thousand acres in this unit. So to answer your question, no, we need more data before I would feel comfortable as a reservoir engineer recommending that we went at least in the north half of the unit on an 80-acre development basis.

Q. Is the initial concept for the pilot to encompass just these six wells?

A. Only these six wells.

Q. Let's turn to the next step following Mr. Soni's simulation. He has given you some forecasts of the performance of the increased-density wells, which would take you down to 80-acre spacing in a 320. Have you received that information?

A. Yes, I have.

Q. And have you done the economic analysis to determine whether those increased-density wells can be drilled at a profit?

A. Yes, sir, we have --

Q. Let's look at that, if you'll turn to Exhibit 35. Describe for us what you're concluding here.

A. A couple of things I'd like to draw your attention to. One, the reserves are the Mesaverde and Dakota reserves combined, and those are incremental reserves. There's no acceleration component to those reserves, so they're, quote, new reserves. Project life is approximately 30-some years.

We built these economics on an 8/8 basis, assuming a 1/8 override, spending roughly $500,000 to drill and complete each well, and the economic indicators after tax are as follows: On a ten-percent discount rate basis, our net present value is $462,000, rate of return 38 percent, payout period some 43 months, and the PI at 9 percent is 2.1. And just so there's not any confusion on that, that's getting back roughly two dollars for each dollar you spend, because there's a lot of interpretation on what PI stands for. But to Conoco, that's what PI is.

I might point out one other real quick thing, is, the economics, if I could kind of summarize, are fairly robust. Using just incremental reserves, the economics very much support this type of drilling.

Q. Let's turn to the proposed procedure. If you'll look on Exhibit 36, summarize for us what you're proposing to do with these pilot wells.

A. Yes, the first three stages -- What I've outlined here, just to kind of clarify things here, is what we are proposing to do. And the first three steps are essentially what we do normally anyhow, which is to drill and complete the Dakota in a usual manner, being, we drill, case, perforate and frac the Dakota.

Now, where these six wells would vary a little from what we would normally do, is -- what we're proposing to do is run bottomhole pressure gauges and measure the pressure and use that data as I've already discussed.

Starting with step 6) we go back to what we would normally do, and that is to complete the Mesaverde -- Well, back up a step here. We'd have to isolate the Dakota and then complete the Mesaverde. Once that step is done, we would go back, pull the plugs, and then commingle the Dakota and the Mesaverde.

So we've added some additional steps here because of the fact that we need the pressure data and we need to run some gauges in the hole, and that does add to the procedure a little bit.

Q. Is Conoco's procedure for drilling these wells as commingled wellbores -- does that continue to be an effective and efficient means of extracting the recoverable gas from both pools?

A. We think it's an extremely effective way to do it. Given the marginal nature of the reservoirs, at least in the San Juan 28-7, as we've discussed here a little bit this morning, it is a very good way to go about doing that.

Q. Let me have you direct your attention to the historical performance of the Dakota wells in the unit. If you'll take a moment and identify and describe Exhibit 37.

A. The last exhibit, Exhibit 37, is simply a copy or a printout of a *Dwight's* plot, of a *Dwight's* database which is in the public domain. And what this plot is showing are just the San Juan 28-7 Unit Dakota wells. It's a summary plot of all the wells combined, starting in 1970. And if you look at 1998 and beyond, we're producing approximately 15 million a day from the Dakota, from some 150 wellbores.

One last thing, you look on the bottom, you see gas cum. We've made some 117 BCF from this reservoir. So it's been a very good reservoir to produce, and obviously we feel there's more potential to grow that asset.

Q. Okay. Summarize for the Examiner what your engineering opinions are, Mr. Shannon, that support your conclusion that this project should be approved.

A. Okay, the primary thing that I'd focus on again is the work that we did with the pressure across the unit. And knowing what we know about the Dakota and given the tight nature of the permeability and this sort of thing, we're seeing a lot of variation, and we're also seeing a lot of areas within 28-7 where there's very minimal pressure loss after some 40 years of production.

So on the basis of what I'm seeing there, the geologic testimony that we heard earlier, the modeling work that has been done, we believe that we need to drill, in this case, six additional wells to test the concept of drilling and producing on 80-acre spacing.

MR. KELLAHIN: That concludes my examination of Mr. Shannon. We move the introduction of his Exhibits 33 through 37.

EXAMINER CATANACH: Exhibits 33 through 37 will be admitted as evidence.

Mr. Cavin?

MR. CAVIN: No, Mr. Examiner, no questions.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Shannon, can you summarize briefly for me how these locations were picked again?

A. Yes. What we attempted to do is, in each location, was to choose an area where we would best represent what a true 80-acre well would look like, if you will. And by that what I mean is, it's completely surrounded by Dakota producers.

We intentionally did not go to areas where there were large areas of undeveloped Dakota reservoir. We wanted to see -- and this is really the basis of choosing these locations -- we wanted to see what a Dakota well would produce, given the fact that it's completely surrounded by offset Dakota producers, and that was the primary basis for those six locations.

One other thing I should add. We also wanted to cover a large geographic area with those six wells. So obviously they're not bunched up. They span the northeast quadrant of the unit, and that's also by intent.

Q. Do the economics for -- Do the economics don't work for drilling this single Dakota well?

A. We have to qualify "don't work". Could you drill a Dakota well and make a return on your investment? Marginally, you could.

Our position has been, if you would recall from two years -- three -- four years ago, when we first started talking about downhole commingling, was that efficiency, and especially capital efficiency, is reached by doing the downhole commingling and combining the two.

Given today's economic climate, I'm inclined to say that drilling a Dakota single in this area would be extremely difficult to justify economically. We really do need the Mesaverde as part of the completion.

Q. In your economic evaluation, is this an area that you believe will be approved for 80-acre Mesaverde production?

A. I think it will be very close to this because, again, the flow stream was based on actual modeled volumes. As far as the capital and operating expenditures, they're very close to what we're already experiencing.

So yes, sir, I think this is a good representation. It certainly gets us in the ballpark to what we would see if you were to go out and commercially develop on 80 acres.

Q. The reserves that you attributed to, is that about half and half, or --

A. It is a little more than half for the Dakota. The Dakota gets a little more of the lion's share of the reserves. The Mesaverde, given the fact that it's a little more permeable, and there's also a higher percentage of acceleration going on in the Mesaverde, so that's why it's more like 55-45, Dakota.

Q. How long do you intend to run pressure -- Do you intend to run pressure buildup tests on the Dakota?

A. Yes, sir, we intend to run it on each of the six wells.

Q. And how long is that going to be, do you think?

A. I would like to see us go for at least 30 days. And one of the things that I've proposed to our management supervision on these wells is that we at least consider pulling the bombs and evaluate how that pressure test is going. If, indeed, we're seeing what we need to see, at least from a reservoir-engineering perspective, that would be long enough. If not, we'll run the bombs back in.

The three wells that I alluded to earlier, we didn't do that. We ran bombs, set the clocks, and when the clocks were up the test was over.

What I'd like to do on this go-around is to actually pull the bombs and take a look at the data, and indeed, if the data is sufficient to tell us what we need to see, then that would terminate the test. Otherwise, we would rerun the bombs with the well still shut in. We've discussed that internally and think that would probably be the best way to go.

Q. How long are you going to flow the Dakota?

A. Again, I would like to see us test for at least 30 days. There again, given the caveat that we see what we want to see, if the wells are not declining at a rate that I would predict, or at least not consistent with our modeling, this sort of thing, then we would need to test them longer. But as a minimum, I'd like to see 30 days, to see what the wells are going to do.

Typically, Dakota wells are going to stabilize a little sooner than that. So I would be surprised if we need to go past that point. But if we do, I'm prepared to recommend to our staff that we continue to test the Dakota before we do anything with the Mesaverde.

Q. Do you plan on flow-testing the Mesaverde separately?

A. Yes. Once we get the Dakota data, we'll set -- as we would normally, we'll set a plug and then come up, perforate and put the Mesaverde on test and get a stabilized rate. And once we're comfortable that we have a stabilized rate, then we'll go back in, take the plug out that isolates the Dakota, and put them on production.

And that is pretty standard fair for our company. That is a typical completion.

Q. How would allocate production at that point?

A. The way we always allocate production, that is, based on stabilized rates, the subtraction-method-type allocation or a ratio where you know what the Mesaverde has produced on tests, you know what the Dakota has produced on test, and you have a ratio of the two, and you allocate based on that ratio.

Q. Do they decline at similar rates?

A. They decline at almost exactly the same rates, hence the reason that the downhole commingle was originally granted, at least as I understand it. But having looked at numerous decline curves in the Dakota and the Mesaverde, as well as some of the shallower intervals, they all seem to decline at very similar rates.

And that could well be given to the fact that you have fractures, as Mr. Johnson testified earlier, running through all of these various reservoirs. They do decline very similarly.

Q. Did you consider -- For purposes of testing the producing rates, did you consider dually completing these wells at all?

A. We have had discussions on dual completions, and our conclusions were that it's quite a bit more expensive to dually complete wells. Naturally, if the reservoirs did not decline at the same rates, you would probably have to do that. In the early days of the unit, that's exactly what was done.

But no, given the economics of dually completing wells versus downhole commingles, we feel that this is the right way to go. I mean, you're -- a lot of confidence in the production rates and the allocations and such.

Q. How long do you think it's going to evaluate your pilot?

A. Well, there's several things that I feel would need to be done.

Number one, and foremost, is to take that data and go back and revisit the model that Mr. Soni alluded to and discussed earlier. And that's going to take some time, because one of the things that I would propose that Conoco consider is expanding the scope of that model, and Mr. Soni described that in his testimony.

I would feel comfortable with at least a year. I would like to get the results and re-look at that model and come back to you and share those results with you. But I feel that it would take a year, from the time we get the data to where we actually felt comfortable with what we were seeing and doing some -- you know, making some additional recommendations or whatever.

Modeling takes a long time, as I've learned, with this exercise. There's a lot of effort that goes into that. And given the nature of this reservoir, it would take some time.

EXAMINER CATANACH: Frank?

EXAMINATION

BY MR. CHAVEZ:

Q. Mr. Shannon, did your bottomhole pressure testing reveal the effects of layered reservoir?

A. No, as a matter of fact, in each of the three cases I didn't see any boundaries. And if I can refer back just a second to that particular exhibit -- I believe that was Exhibit 34 -- I noted in number 1) under "Conclusions" -- I didn't state this in my earlier testimony -- we didn't see any boundaries. And in fact, in all three cases, pressure was still building.

So obviously the tests weren't run long enough that you would ever see beyond the transient flow, which could be as much as a year. So we didn't see any layering, we didn't see any boundaries, pinchouts or anything of that nature.

And that's not too surprising, given the nature of the rock, being as tight as it is. Compared to all of the transient tests I've seen in my career with Conoco, these are some of the tightest rocks I've ever looked at, and I didn't see anything of a barrier or layering, as you've described.

Q. Well, given the uniformity -- that's my word -- what appears to be some type of uniformity throughout the unit and the reservoir, would you estimate that the original gas in place would be pretty much the same throughout the Dakota interval in that unit?

A. It would, with one caveat. Remember what we were talking about earlier in Mr. Johnson's testimony. If we concern ourselves with the north and east part of the unit, I would agree with you. As we move south and west, if I understand your question, we're losing pay quality and this sort of thing, and obviously gas in place is going to vary down there.

But where we're talking about where these pilot wells are, I would agree that there's a lot of uniformity in gas in place.

Q. When you talk about pay quality changing --

A. Well, if you recall, we were talking earlier about some of the reservoirs, especially in the middle part of the unit, getting very, very poor or completely disappearing, this sort of thing. So it's just the pay quality changes as you move from the north to the south part of the unit.

Q. Have you been able to -- or tried to quantify the differences in gas in place due to that change?

A. I have not personally. There was a reservoir management plan or a depletion strategy that was done about five years ago by Conoco on this unit, and that study did evaluate gas in place and this sort of thing. But I have not personally made that evaluation, no.

Q. When you've used the sensitivity models, the different -- the sensitivities were changed in the reservoir, do you think that they covered pretty much what would be changes in the reservoir across the unit?

A. I do. Given the fact that -- Let's start with the permeability, for example. What I've seen, what I've calculated, and then what my predecessors have calculated on permeability, there is a bit of consistency there.

And if you go back to the exhibit that Mr. Soni talked about, the permeability, sensitivities, that sort of thing, in my opinion that definitely captures the high and low range, if you will, of what the permeability is. So I felt very comfortable with that level of analysis.

Q. Well, given that the models probably cover the unit, wouldn't there be enough gas in place left, perhaps, in the lower-quality of the reservoir, given your economics of the models, to perhaps even include them for further drilling?

A. Could be. And we talked a little bit earlier about some of the drilling that we've done just in 1998 in the southwest part of the unit. And I'm not ruling that area out. It just -- The pilot that we're here to talk about today is focused more up in this region here.

But I would not rule out the southwest area ultimately. I agree with you.

Q. Are you intending in your drilling program to go ahead and just straight drill all these -- just drill all these wells and start capturing data, or perhaps drill one or two and capture some data before you drill the others? What is your plan?

A. Our plan is to drill all of the wells at one time, and the reason for that is, again, a matter of economics. To drill a well and then release a rig is just not feasible. We need to drill the wells and at least case them as a program, back to back wells, and not stop drilling.

I don't think -- and I'm speculating here -- I don't think that we're going to see necessarily any data that would cause us not to want to drill the next three wells, say we're on well three and we're going to see something that would cause us not to drill any more wells.

I would like to see all six wells drilled and all six wells tested for the reasons that we described.

Q. Do you anticipate -- I may have misunderstood your discussion earlier -- that you will be completely testing the Dakota zones before you --

A. Uh-huh.

Q. -- do a Mesaverde completion?

A. Yes, sir, uh-huh.

MR. CHAVEZ: Thanks, that's all. The BLM has some questions.

EXAMINER CATANACH: Yes, sir.

EXAMINATION

BY MR. LOVATO:

Q. I'm Jim Lovato of the Bureau of Land Management out of Farmington. Just a couple of questions for you.

A. Sure.

Q. Question of clarification. I think in Exhibit 2 you indicated that the pilot for the spacing would actually be 100-acre spacing, but yet the rest of the exhibits talk about 80 acres. Would you clarify?

A. Yes, I'll try to clean that up a bit. What we're asking for here is 80. We described 100 in-house, being that it was the third well in a 320, and that equates roughly to a 107-acre spacing. I didn't mean to trip anyone up with that. It's -- Really, what we're talking about here is 80s, 80-acre. That's confused some folks in our camp as well, and I apologize for that.

Q. Thank you. The p.s.i.-per-year map, how were the buildups determined? And what I mean by that is, you know, obviously the permeability is a variable here --

A. Uh-huh.

Q. -- and the duration of the shut-ins and the buildups --

A. Uh-huh.

Q. -- was that consistent across the board, or did it vary?

A. Well, for the bulk of the map, the bulk of the pressure data that I used was actually data that's in the public domain now, and those were original pressures that were reported.

And in fact, in the wells that were drilled in the Fifties and Sixties, they would have been shut in for 60, 70, 80 days in some cases. And I'm speculating, but I would assume that they were waiting on pipeline connection.

And those were very good pressures to have. Those were not downhole pressures like the three that I described here, but nonetheless, that was good data, considering the fact that those wells had been shut in for that length of time.

So we have kind of a mix of pressure data. The three that I've described were actually wells where we took pressure data, downhole pressure, with a very, very highly precise gauge.

All of the other data is data that's in the public domain that you can get right out of *Dwight's*, and I used that data for those wells.

Q. Okay, so that subsequent well buildup information, it could have seven-day buildups, it could have been 30. There's no consistency, or is there?

A. Oh, I'm sorry, in the three that we did?

Q. No, no, on the p.s.i.-per-year map --

A. Oh, okay.

Q. -- I think you had it at various time intervals.

A. Oh. Oh, I see, yes. Yes, right.

Q. Right, and again, the duration of the shut-in, that's the question, were they consistent?

A. To be honest about that, the pressures were not -- or the shut-in times were not totally consistent.

The earliest wells, again being those in the Fifties and Sixties, frequently were shut in for two or three months at a time. The more recent wells, I don't believe they were, so there's not consistency in that respect.

MR. LOVATO: Okay. Now, the simulations there, as far as the permeability, you get back to the p.s.i.-per-year map, was K solved for in that analysis? I guess I can direct my question to Mr. Soni on that one. On your history match.

MR. SONI: I didn't follow your question.

MR. LOVATO: Did you solve for permeability in the history match? I know you were solving for your gas in place and some other parameters, but did you try to back-solve for permeability?

MR. SONI: Yes, that's how we got the initial --

MR. LOVATO: Okay, so did that match pretty well with the PTA analysis that you have on your early wells, as well as the other buildup data?

MR. SONI: Yes.

MR. LOVATO: Okay, all right. Now, Mr. Chavez alluded to this here too. It's a three-layer model. What were the results on a single-layer model?

MR. SHANNON: I'm not prepared to answer that. I'm not in a position --

MR. LOVATO: You didn't run a single-layer model on it?

MR. SONI: No, we didn't.

MR. LOVATO: Okay, all right. But geologically and performancewise, the wells behaved as a single layer?

MR. SHANNON: I believe that's correct.

MR. LOVATO: Okay. And just for the record here, we haven't had any consultation at all with Conoco regarding the technical aspects, just the timing of the --

MR. SHANNON: Uh-huh.

MR. LOVATO: -- hearing. So we'd like to meet with Conoco in the future really to discuss some of the nuts and bolts and the technical aspects of it and just reserve the right to go ahead and comment to the Commission regarding those findings on this. Thanks.

EXAMINER CATANACH: Anything further of this witness? If not, he may be excused.

What else?

MR. KELLAHIN: That's it. We're through, Mr. Examiner.

EXAMINER CATANACH: Mr. Cavin, are you -- any statements or anything else that you'd like to --

MR. CAVIN: No, Mr. Examiner, we're satisfied. This is helpful, figuring out the estate's interest and the impact on its interest.

EXAMINER CATANACH: There was a previous motion to continue. Are you now not going to pursue that?

MR. CAVIN: Yes, sir, that's correct.

EXAMINER CATANACH: Okay. Mr. Kellahin, is there any effect of the location changes? Is that -- Do we need to talk about that at all?

MR. KELLAHIN: No, sir, the changes in the location involve wells that are still standard well locations. The four that are unorthodox remain unchanged. They are as we showed you in our Application.

EXAMINER CATANACH: But was notice of those well locations sent to anybody?

MR. KELLAHIN: They were originally sent, but the original notice had the error in the location, but the well stayed standard anyway. We wouldn't notify anyone for a standard well location.

EXAMINER CATANACH: Okay.

Okay, anything further?

MR. KELLAHIN: No, sir.

EXAMINER CATANACH: There being nothing further, Case --

MR. CHAVEZ: Mr. Examiner, there was one issue. Mr. Klein, I think, was going to try to resolve the issue of spacing on the west half of Section 18.

MR. KLEIN: Yeah, I can look into that. That was done when El Paso operated the unit back in the Fifties and in the Seventies, and we took over operatorship just a couple years ago from Amoco. So we have no knowledge, and we'll have to dig through our records, you know, try to investigate to the best of our ability.

EXAMINER CATANACH: Okay. Mr. Klein, if you could supply us with that information that you come across and submit a copy also to Mr. Chavez up in Aztec.

MR. KLEIN: Okay. Yeah, we should have documentation in the files somewhere that we got from Amoco. They turned over supposedly all their operators' files to us. So somewhere in there, there should be some history on this.

EXAMINER CATANACH: Okay. All right, there being nothing further, Case 12,122 will be taken under advisement.

(Thereupon, these proceedings were concluded at 11:00 a.m.)

* * *

heard by me on 9/4/ 12122, 98

David R. Catanach

Oil Conservation Division

CERTIFICATE OF REPORTER

STATE OF NEW MEXICO)
) ss.
COUNTY OF SANTA FE)

I, Steven T. Brenner, Certified Court Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation Division was reported by me; that I transcribed my notes; and that the foregoing is a true and accurate record of the proceedings.

I FURTHER CERTIFY that I am not a relative or employee of any of the parties or attorneys involved in this matter and that I have no personal interest in the final disposition of this matter.

WITNESS MY HAND AND SEAL February 8th, 1999.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 2002