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. 13,888
APPLICATION OF BURLINGTON RESOURCES OIL AND GAS COMPANY, L.P., FOR APPROVAL OF A PILOT INFILL WELL PROJECT WITHIN THE SAN JUAN 27-5 UNIT, RIO ARRIBA COUNTY, NEW MEXICO	

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: WILLIAM V. JONES, Jr., Hearing Examiner

March 15th, 2007

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, WILLIAM V. JONES, Jr., Hearing Examiner, on Thursday, March 15th, 2007, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South Saint Francis Drive, Room 102, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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I N D E X

March 15th, 2007
Examiner Hearing
CASE NO. 13,888

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A P P E A R A N C E S

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* * *

WHEREUPON, the following proceedings were had at 10:55 a.m.:

EXAMINER JONES: Okay, let's go back on the record this morning and call Case Number 13,888, Application of Burlington Resources Oil and Gas Company, L.P., for approval of a pilot infill well project within the San Juan 27-5 Unit, Rio Arriba County, New Mexico.

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, and I have two witnesses to be sworn.

EXAMINER JONES: Any other appearances?

Will the witnesses please stand to be sworn?

(Thereupon, the witnesses were sworn.)

MR. KELLAHIN: Mr. Examiner, by way of introduction we have before you a three-ring binder that has the hard copies of the PowerPoint presentation.

In addition, we have put in the cover of your book a copy of the PowerPoint presentation, and so the DVD disk there for you will show you the same presentation you're about to see here.

The exhibits are in the same order in the book as you're going to see on the PowerPoint. I may for convenience skip around in the first part to get you oriented.

The concept is, currently within the 27-5 Unit -- it's one of the large federal units in the San Juan Basin. Burlington Resources continues to be the operator of that unit. Within Section 8 of that unit, which is internal from the outer boundaries, within Section 8, they have targeted Section 8 for a pilot project. Within the unit itself, the density for Dakota -- for Mesaverde wells can be four wells to a section. We're on -- no, it's more, it's eight wells to a section. We can do 80-acre density.

And so what we're looking at here is to provide the opportunity so that we can test on 40-acre density to see if the pilot project, based upon the computer modeling, will in reality support that density. So when you look at Section 8 you're going to see how it's currently developed. We're going to target for you the proposed infill pilot wells.

You will note that the pilot wells are all being drilled from various islands within that section and directionally drilled. Part of that reason was to have an economy of effort to use the least amount of surface disturbance that would be required to initiate these wells, and the plats will demonstrate that for you.

The Application asks for you to approve the concept of directional drilling. The actual details of themselves will be submitted to the District under the administrative processing so that they will have the directional plan in the C-102 that has all these locations on it, and then there'll be the vertical plan. So what we're going to show you today is the concept, and request that you authorize the Division District, as they can do now under the administrative process, to approve the wells themselves.

The presentation you're about to see has been made to the Bureau of Land Management. We have obtained their concurrence. The concept has been generated among all the working interest owners, and we have a substantial approval from the working interest owners. It has been -- this same presentation has been made to the District Office in Aztec, and with your permission we'll go forward and make that presentation to you today.

<u>K.W. CRYER</u>,

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. My name is K.W. Cryer, and I'm a landman for Burlington Resources, which is a wholly owned subsidiary of

ConocoPhillips Corporation.

Q. Mr. Cryer, where do you reside?

A. Farmington, New Mexico.

Q. On prior occasions have you qualified before the Division as an expert petroleum landman?

A. No, I have not.

Q. Summarize for us your education.

A. I graduated with a bachelor's of business administration in petroleum land management from the University of Oklahoma in 2006. I have worked with ConocoPhillips since June. I have worked in mostly federal units, and now starting to get on the fee lands as well.

Q. Among your responsibilities, have you been designated the responsibility to deal with the land matters within this unit concerning this pilot project?

A. Yes, sir, I have. I have retrieved the ownership list in the participating areas within the unit and have been in contact with them.

Q. As part of your process, have you and others under your direction initiated proposals for the pilot project to the working interest owners in the unit?

A. Yes, we have. We've sent out a letter, a ballot letter, to get them to join in to the pilot project.

Q. To the best of your knowledge and information, are you currently working with a current list of those working interest owners and participants?

A. Yes, this is based off our Division order system, and we believe it is the most current representation of ownership.

MR. KELLAHIN: At this time, Mr. Examiner, we tender Mr. Cryer as an expert petroleum landman.

EXAMINER JONES: Mr. Cryer, did you grow up in New Mexico or --

THE WITNESS: Oklahoma.

EXAMINER JONES: Okay. Well, that's a new state.

Okay, Mr. Cryer is qualified as an expert petroleum landman.

MR. KELLAHIN: With the assistance of Mr. Roberts, who is the petroleum engineer who will testify in a moment, I'm going to have him run the PowerPoint, and we'll have Mr. Cryer refer to different things.

Let's start by flipping over and finding the display that shows the area map. I think it's behind Tab Number 3, Mr. Examiner, the first exhibit behind Tab 3.

Q. (By Mr. Kellahin) Mr. Cryer, what are we looking at here?

A. Mr. Examiner, we're looking at a locator map of the approximate location of the San Juan 27-and-5 Unit. And you notice, you can see the Navajo Reservoir, the towns of Bloomfield, Farmington and Aztec.

Q. Is this a fully formed, continually approved federal unit?
A. Yes.
Q. It's an exploratory unit?
A. Yes.
Q. Are there participating areas in this unit?
A. Yes, there are. The Mesaverde and Dakota participating areas are fully developed within the unit.
Q. Do you have a display that targets the section involved with the San Juan 27-and-5 Unit?
A. Yes, in the next page behind Exhibit Tab 3 we have outlined in red the section in question and the development of the wells within that section and the unit.
Q. The entire unit area, then, has been approved as a participating area for the Mesaverde?
A. Yes, sir.
Q. As well as --
A. As well as the Dakota.
Q. The Dakota too?
A. Yes, sir.
Q. Let's turn now and let's go through Exhibit 1, and starting with the Application itself let's go through and identify the attachments behind Exhibit Number 1, starting off with the Application itself.
A. Okay. Behind Exhibit Tab 1 is the Application we

submitted for the 27-5 Infill Pilot Project.

Q. The first attachment, then, to the Application is?

A. This is another locator map that we submitted to the Conservation Division.

Q. And behind that is what?

A. This is a current list of the wells within this section, of Section 8 of 27-5 Unit.

Q. Is there also a display that shows all the proposed project wells that are to be added to the section?

A. Yes, on the next page there is a list of the proposed wells that we have. There are 17 total wells, 14 of them are Mesaverde-Dakota commingles, two pressure observation wells, and one Dakota stand-alone.

Q. When we look at this tabulation of wells and their location, does this include just the surface location, or is the bottomhole location also reflected?

A. The bottomhole location is reflected.

Q. Well, I'm -- I think you're mistaken --

A. Oh, I'm sorry.

Q. -- yeah, look again.

A. Oh, no, it is not, I'm sorry.

MR. KELLAHIN: The footages, Mr. Examiner, are just for the surface.

THE WITNESS: I apologize.

MR. KELLAHIN: We'll have to supply the bottomhole locations when they've been surveyed in.

EXAMINER JONES: On Exhibit C it's just surface?

MR. KELLAHIN: Those are just surface.

MR. ROBERTS: I notice the third column from the right --

MR. KELLAHIN: That's just the unit letter. So all we have is a unit letter, and we don't have the footages for you.

EXAMINER JONES: Okay.

Q. (By Mr. Kellahin) Is there a naming or a well-identification problem now that you're trying to resolve with the OCD Aztec Office on how to name these wells?

A. Yes, there is. If you notice, behind the well number there's a P. That simply stands for proposed. They do not have the capacity to handle an additional amount of wells, so we're currently working with them to change their databases and -- to allow for that to happen.

EXAMINER JONES: We have an abacus, we don't have a computer.

Q. (By Mr. Kellahin) Well, when that's resolved, then, you'll file your APDs and your appropriate forms to get the surface and the bottomhole locations established on record before the Division?

A. Yes.

Q. Let's turn behind the identification for the wells and find what's the next display.

A. You're referring to Exhibit 2?

Q. Well, there should have been a locator map somewhere.

A. Yes, I'm sorry, okay. Yeah, look at -- described as Exhibit D is a locator map of the wells. As you can see, what we try to is take the existing wells and then, obviously, like he said, drilling directionally into the different --

Q. Let's turn now to Exhibit Number 2 and look at the documents behind Exhibit Number 2. What's the first thing we find?

A. This is a proposal letter for the working interest owners in the 27-and-5 participating areas for the Mesaverde and Dakota formations. We sent this out by certified letter to all of the working interest owners.

Q. What's the current status of your voluntary commitment percentages for this project?

A. We're -- on both formations, we're up over 99 percent on both. And simply, I think the last part was a no-response and not a no.

Q. Six pages back in Exhibit 2 there's a letter from the Bureau of Land Management.

A. Yes.

Q. Do you see that?

A. On January 18th we held a meeting, as we talked about earlier, with the Bureau of Land Management and the New Mexico Oil Conservation Division and gave them this same thing, and out of that meeting they gave a letter of their support for us, and this is what this letter is.

Q. While it's not a slide in the PowerPoint, Mr. Examiner, behind Exhibit Tab Number 2, the next display is Mr. Alexander's certificate of mailing.

Mr. Cryer, for purposes of this hearing did Burlington cause copies of the Application and the notice of hearing to be sent to all the working interest owners in the unit?

A. Yes, we did, we submitted a letter February 23rd.

Q. And when we turn behind Mr. Alexander's certificate, there's a notice letter over my signature of February 12th? Keep going. Under 2 [*sic*].

A. I think I grabbed the wrong book, I'm sorry.

Q. It's all right. Is this an accurate copy of the notice letter that Burlington sent to the working interest owners?

A. Yes, and it is very accurate.

Q. And the tabulation of parties that were sent that notice was prepared by Burlington?

A. Uh-huh.

Q. And it's the same master list that you've used for the unit?

A. Yes, it is.

Q. When we turn past the letter there's a tabulation of those interest owners in a hard copy, and behind the hard copy, then, are copies of the return receipt cards, are there not?

A. Yes, there are.

Q. And you've re-examined all those cards, have you, Mr. Cryer?

A. Yes. Originally, we kind of got some confused because we sent out two certified letters, one for the proposal for them to join, and one for the notice of the hearing, and we got some confused. But what are in your book are the accurate copies for the hearing.

MR. KELLAHIN: It should be right after the tabulation of interest owners, if you flip --

MR. BROOKS: What tab?

MR. KELLAHIN: It should be behind -- Mine is behind Number 2.

THE WITNESS: I think they're behind 1.

MR. BROOKS: I don't think they're in here.

THE WITNESS: They're in 1.

MR. BROOKS: Oh, well, then --

THE WITNESS: Yeah, I'm sorry.

MR. KELLAHIN: Behind Number 1. Yeah, your hand is on --

EXAMINER JONES: Number 1. There it is.

MR. KELLAHIN: There it is.

MR. BROOKS: Okay, thanks.

Q. (By Mr. Kellahin) As a result of those mailings and those proposals, have you received any objection from any interest owner?

A. Not -- no one.

Q. We've covered the items in Exhibit Number 3. Let's turn to Tab 4 and look at the documents behind Tab 4. What are you demonstrating here, Mr. Cryer?

A. This is a chronology of events involving the 27-and-5 Infill Pilot Program.

Q. When did this chronology begin?

A. January 15th, 2005.

Q. And where are we now with this chronology?

A. We are currently on the second page, present-day at the hearing.

Q. And so these are the major topics in the chronology affecting the pilot project?

A. Yes, they are.

MR. KELLAHIN: With your permission, Mr. Examiner, that concludes my examination of Mr. Cryer.

We move the introduction of the exhibits that he's testified to. They are exhibits behind Tabs 1 through 4.

EXAMINER JONES: Exhibits that are behind Tabs 1 through 4 will be admitted into evidence.

EXAMINATION

BY EXAMINER JONES:

Q. How big is Section 8, how many acres?

A. 640.

Q. Even 640?

A. I believe so.

Q. And these are both in the same PA, and there was a -- the Mesaverde allows four wells for -- in the Dakota in this instance, or already allows eight then; is that right?

A. Excuse me?

Q. Wells per 640?

A. Yes.

EXAMINER JONES: And do you guys know what order that was? Are you going to go over that in a little bit or -- I can find it if --

MR. KELLAHIN: I've got the reference here for you, Mr. Examiner. Here's a copy of the order that the Division issued on February 3rd of 1998. It's Order Number R-10,989, and it allowed four wells in the 320.

EXAMINER JONES: Okay.

MR. KELLAHIN: In addition, Mr. Examiner, the order will show some flexibility in well locations from the interior quarter quarter lines -- in fact, from any interior line, you can be 10 feet off that line.

EXAMINER JONES: Okay. Are you the one that we should ask about surface locations and picking the locations? You're going to have three witnesses; is that right?

MR. KELLAHIN: Perhaps we ought to save that for the engineer and see --

EXAMINER JONES: Okay.

MR. KELLAHIN: If we can't clear that hurdle, I have other witnesses that could be called.

EXAMINER JONES: Okay. Mr. Alexander is back there, I see.

Q. (By Examiner Jones) POW, what does that mean?

A. Pressure observation well.

MR. BROOKS: Also it usually means pulled out of well.

(Laughter)

MR. BROOKS: Everywhere else it means prisoner of war.

(Laughter)

MR. KELLAHIN: We have some of those around here, don't we?

MR. BROOKS: Well, you know, when I first got into this business I was very confused because I kept seeing POW on the drilling report. Who had the drilling crew taken prisoner?

Q. (By Examiner Jones) Let's see here. Okay, you guys are talking in this case about deviated wells from the same surface location but not any horizontal drilling here; is that --

A. No.

Q. -- correct? Okay.

EXAMINER JONES: And that's -- Mr. Brooks?

MR. BROOKS: I don't think I have any questions.

EXAMINER JONES: We may have questions later, but I think we're done.

MR. KELLAHIN: You can step down.

Mr. Examiner, at this time I'll call Mr. Neale Roberts.

NEALE ROBERTS,

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

A. Neale Roberts. I'm a reservoir engineer for

Burlington Resources, a wholly owned subsidiary of ConocoPhillips.

Q. Where do you reside, sir?

A. I live in Farmington, New Mexico.

Q. On prior occasions have you testified before the Division as a petroleum engineer?

A. No.

Q. Summarize for us your education.

A. I have a bachelor's in petroleum engineering from Colorado School of Mines, 1980.

Q. Subsequent to graduation, where have you been employed and in what capacities?

A. I've been employed numerous places around the world as a reservoir engineer, most recently in Farmington, New Mexico, since 1998.

Q. How long have you been involved in this Mesaverde pilot project in the 27-and-5 Unit?

A. Since 2005.

Q. What are your primary responsibilities for the project?

A. I am responsible for the modeling studies, the original proposal budget and assisting the coordination of the implementation, and data monitoring, gathering and follow-up simulation studies.

Q. As part of that analysis, have you utilized the expertise of petroleum geologists within Burlington?

A. Yes, sir.

Q. Have you found that information to be knowledgeable and accurate?

A. Yes.

Q. As part of your process, have you reviewed all the pressure data that's available within the area?

A. Yes.

Q. And have you reviewed the production data that's available to you as well?

A. Yes.

Q. As a result of that study, do you now have recommendations concerning a pilot project for the Examiner?

A. Yes, I do.

MR. KELLAHIN: At this time, Mr. Examiner, we tender Mr. Roberts as an expert petroleum engineer.

EXAMINER JONES: Mr. Roberts is qualified as expert petroleum reservoir engineer.

Q. (By Mr. Kellahin) Mr. Roberts, let's turn to the PowerPoint presentation and have you commence by telling the Examiner and counsel how you have organized the presentation.

A. Yes, the presentation is divided into three parts, three separate pieces of work, actually. It would begin chronologically with a scoping study, which led to a pilot proposal which we'll discuss, and finally we've done some preliminary modeling work in anticipation of the actual project.

Q. At the conclusion of all the presentation, have you summarized your ultimate conclusions at this point in the project?

A. Yes.

Q. Are those conclusions demonstrating to you the recommendation to the Examiner that he approve the pilot?

A. Yes, sir.

Q. Let's turn now to the infill scoping study. First of all, define for us what you mean by that term.

A. The infill scoping study, which begins with Tab 6, was essentially designed to identify areas of infill potential and select one or more for further analysis or pilot testing, if we were to find any.

Q. In order to do that, what was then required?

A. Basically what we did is described here in this infill scoping study slide. We began with an original-gas-in-place grid and subtracted from that the EUR that we expect to recover under the existing 80-acre development plan, to generate a remaining gas in place at the end of the current development.

That grid, then, was divided by a grid which defined the minimum EUR per well in order to calculate a maximum number of additional wells that can be drilled to recover that gas.

Adding that to the existing wells provided us with the total wells per section, from which we were able to calculate a maximum density per section.

And then as a final step, having generated those figures for the Mesaverde and the Dakota, was to reconcile those numbers, one formation against the other and then of course against the existing development, in order to determine how many wells remain to be drilled in each section.

Q. All right, Mr. Roberts, let's start then with the workflow for the infill scoping study, and if you'll turn to the next slide, let's talk about the Mesaverde original gas in place.

A. Yes, the next slide is provided just as an example of the workflow I just described. This would be the Mesaverde original gas in place, contoured on an MMCF-per-section basis.

The slide following that is the Mesaverde --

Q. Go back a minute, let's --

A. I'm sorry.

Q. -- let me ask you some questions.

A. Okay.

Q. When we look at the plat showing the original gas in place, you've identified in the lower right a red square. What's that?

A. That would locate 27 and 5 on this map.

Q. To the north and west of that square is an area outlined in red that has a meandering shape to it. What does that represent?

A. That is referred to internally as the Mesaverde fracture trend. That's an area of the Basin that we consider to be relatively more fractured than the rest of the Basin.

Q. Do you have your laser pointer, Mr. Roberts? Point that out for us so we can all make sure we're looking at the same thing.

A. Yes, we're talking about this outline here.

Q. Within the shape of that contour is what?

A. Within -- inside of that contour, we believe the rocks are relatively more fractured in the Mesaverde than outside of that contour.

Q. Is the original gas in place based upon a volumetric calculation?

A. Yes, the calculations are made from well logs, a database that we update periodically and generate new maps. This map would represent our most recent interpretation.

Q. Has this geologic map and the subsequent geologic maps been prepared by Burlington geologists?

A. Yes.

Q. And are they relied upon by those geologists in analyzing Mesaverde wells and their locations?

A. Yes.

Q. And do you also rely on them?

A. Yes.

Q. To the best of your knowledge, are they accurate?

A. Yes.

Q. Let's turn, then, to the next slide and look at the resulting projection for the EUR from existing wells. How do we read this display?

A. This is generated by projecting recoveries from all of the active wells in the Basin, using decline curve analysis, summing it at a section level, and then contouring the expected recoveries per section Basinwide.

Q. When you move -- Use your pointer for me. If you move to areas of the green and the reds, within that shade, what are we seeing in those areas that distinguishes them from the areas in the project San Juan 27-and-5 Unit?

A. Right, the contouring, the darker colors indicate higher expected recoveries per section, while the lighter colors anticipate lower recoveries per section, and you see the 27-and-5 unit down here in the southeast is expecting a relatively low recovery per section.

Q. And the recovery within the San Juan 27-and-5 Unit, the EUR is based upon what well density at this point?

A. 80 acres --

Q. Okay.

A. -- per well.

Q. So visually, then, what do you conclude about the display with regards to our project area?

A. The recoveries in the project area we would expect to be low relative to better parts of the Basin in the northwest.

Q. Let's reverse it now and look at the remaining potential. Do you have another slide?

A. This slide displays the difference, in fact, of the previous two maps, which would give us remaining gas in place at the conclusion of the current development. And it shows in the fracture trend and in the better-quality rock in the northwest a very low remaining gas in place, and conversely in the southeastern area with the poor expected recoveries from the 80-acre we see a relatively higher remaining gas in place.

Q. Let's turn to the next point, then, in your presentation and have you analyze and explain to us your minimum economic calculations.

A. Okay, behind Tab 7 there's a chart which displays our work to calculate a minimum EUR per well in order to get break-even economics under different cost scenarios, one assuming a stand-alone well and the other assuming a commingled well.

Q. When we look at this slide, what is the color significance?

A. Well, the red line would represent the relationship between gas price and minimum EUR, assuming commingled costs -- in other words, cost-sharing between the Mesaverde and the Dakota. The green line above the red line, because it is assuming stand-alone cost to develop either formation. So the --

Q. The conclusion with regards to stand-alone versus commingled wells is what at this time?

A. Stand-alone is poorer economics. It permits less development. Commingled costs permit more development of the gas. And obviously, the higher the gas price, the less gas is needed to justify a well.

Q. As part of your Application, are you also seeking to include the Dakota within this, so you can commingle Dakota and Mesaverde?

A. That's correct.

Q. Will there be procedures in place that you can test the zones separately, and within each zone test the zone separately?

A. We expect to run -- we have a significant budget set aside for running spinner surveys periodically throughout the life of these wells.

Q. So the potential of commingling does not adversely affect your science project?

A. No.

Q. Let's turn to the next slide then. It's captioned Maximum Well Density Calculation. What are you doing here?

A. Yes, this just lays out the various assumptions that are in here, in the calculation.

Q. Now this applies only for purposes of the scoping study?

A. That's correct, that's correct. Throughout this section of the presentation we're talking only about the scoping study.

Q. And how is that different from the pilot study?

A. The pilot study is a more rigorous methodology employing three-dimensional numerical modeling which can easily discern between acceleration and new development, as well as the interference effects between wells and so forth.

Q. Well take us, then, through your analysis of the scoping study and talk about the assumptions you make.

A. Right, for the sake of simplicity in a Basinwide scoping study, these assumptions were basically necessary to permit the study. But we assume that each section is a homogeneous tank, that the wells in each section would divide the remaining gas equally, they would be drilled simultaneously, we would not consider any effects of acceleration nor any possibilities for recompletions to access gas, and we would assume further that the density would only progress geometrically.

Q. Take us to the next slide. What are you showing us here?

A. This is the result of that calculation. It is still subject to reconciliation between the two formations and existing development, so you see a chart for the Mesaverde on the bottom left that shows both cases, stand-alone and commingled, and a chart on the lower right for the Dakota, similar to the Mesaverde.

It remains to -- as I said, to reconcile the two formations, you know, to confirm that all the commingle opportunities are taken advantage of first before any stand-alones are contemplated. And then of course, the existing wells also have to be considered.

Q. Okay, let's turn to Exhibit Tab 8 and look at the first slide behind Exhibit Tab 8. Within Exhibit Tab 8, what are you demonstrating with these various slides that we're about to look at?

A. These are maps which show the maximum possible density per section following the reconciliation that I described at various gas prices for the two different formations.

Q. Why is that important for you?

A. We showed earlier that a project like this is sensitive to gas prices, and so -- you know, nobody of course can be certain of the future, as far as what the prices might be, so we like to look at various sensitivities to that gas price.

Q. Show those to us.

A. Okay, this first slide is generated at five dollars an MCF. And then the other important feature of these maps is to kind of locate where the potential is, and you see all along the southwestern side of the Mesaverde field there is some potential to increase spacing to 40s, and possibly 20s in some small areas at five-dollar gas.

Q. The area shaded in pink, which is a substantial portion of the 27-and-5 unit --

A. Right, the green is all currently approved, the red shades would require new rules. And this -- the first kind of shade of reddish hues is the sections that could possibly justify 40-acre densities.

Q. So at this point in the analysis, if we look at Section 27-and-5 unit, there are further opportunities in the Basin to extrapolate the success, if you have them, in the pilot and put them elsewhere in the unit -- in the --

A. Yes.

Q. -- in the Basin?

A. Yes.

Q. Distinguish this one from the next one in terms of what happens to the color codes. Let's look at the seven-dollar case.

A. The next slide is the same information interpreted at seven dollars per MCF, and you see there is an expanding area of 40-acre potential, as well as some growth in the 20-acre potential.

Q. Okay, let's look at the last one for the Mesaverde at the ten-dollar level.

A. Similar to the previous slide, all the areas expanding.

Q. Using this methodology, let's turn to the Dakota and look at the five-dollar example in the Dakota.

A. Here at five dollars you find the potential primarily located in the southeast, with some in 27-and-5 and west and south of there.

Q. And as we move to the seven-dollar example in the Dakota, what happens?

A. Similar to the previous examples, you see the areas of 40- and 20-acre potential expanding.

Q. Okay, and then the ten dollars in the Dakota?

A. And ten dollars, you see a large increase in the potential areas for development.

Q. Let's go now to Exhibit Tab 9 and talk about the slides behind Exhibit Tab 9. What are you doing now?

A. What we've done in this first slide is, we've looked at an area that we refer to as the southeast federal units area, which we operate in the southeastern part of the Basin and tried to quantify the opportunities that might exist for us at a 40-acre density at different gas prices. And this includes the stand-alone Mesaverde opportunity, stand-alone Dakota opportunities, and then Mesaverde and Dakota commingled opportunities.

Q. The colors may have been more clearly expressed if you look at the hard copy.

A. Yeah.

Q. What's the conclusion, then?

A. The conclusion is that there is a significant potential for additional development drilling within a reasonable range of gas price assumptions.

Q. At this point, then, you've concluded the scoping study and determined within a certain area there's a feasibility for this?

A. Yes.

Q. And you now make a translation into identifying exactly what you would do within the pilot area?

A. That's correct.

Q. Let's look at that. And your conclusions, then, when we leave the first part of the presentations, are what?

A. Yeah, we believe that 40-acre infilling appears to be quite possible under various reasonable assumptions of future gas prices. We see an overlap in the Dakota and Mesaverde potential in the southeast federal units area, and we have recommended an infill pilot in the northwestern quarter of 27 North and 5 West.

Q. Now when we move into the infill pilot proposal itself, how did you determine that Section 8 in 27-and-5 ought to be the pilot area?

A. We felt from a geology and reservoir perspective that it was more or less representative of the potential that we see in that area. Our midstream people advised us that there's a trunk line running through the middle of Section 8 that will assist us with offtake capacity for a large production increase. We have considerable high quality data in the area in the way of log data, as well as later pressure tests.

Q. Is this the best of the Mesaverde or the Dakota?

A. No, as far as infill potential, no, it's typical of this area.

Q. Let's look at your specific project objectives for the pilot. If you'll turn to Slide 10.

A. Behind Exhibit 10. Our objective is to create a development plan for the southeast federal units area that's optimized under the current cost and price environment, because we feel that that is the most efficient in terms of surface disturbance and reservoir depletion, and it also provides the maximum net present value for the unit mineral owners.

Q. Let's go to the slide that helps to quantify the magnitude of the opportunity here if the pilot is successful.

A. Yes, as we concluded our feasibility study and looked to 27-and-5, the first thing we did was kind of tabulate some of the volumetric numbers to have a look at where we were there. And what we see is that -- just quickly, is, the original gas in place under the unit was in the order of 1.4 TCF. The cumulative production as of June, 2006, is just over 360 BCF, giving us a current recovery of about 26 percent.

Q. How many years did it take to do that?

A. It took over 50 years to get to 26-percent recovery.

Q. And how are you examining the opportunity to get some of the rest?

A. This hearing is to look at the possibility of increasing the density.

Q. What are the numbers that you have below the green?

A. The other, I guess, main point here is, using decline curve analysis we anticipate additional recovery of something on the order of 350 BCF, which would bring us to about a 50-percent ultimate recovery under 80-acre density.

Q. What type of drive mechanism is associated with the Mesaverde?

A. It's a volumetric depletion gas reservoir, and for that type of reservoir we feel like we -- it's reasonable to try to get higher -- a better recovery.

Q. Let's turn to the next slide now. What are you illustrating here, Mr. Roberts?

A. This is just some discussion of the figures presented on the previous slide. If we start with the cumulative production, I think everyone should agree that those are hard numbers. That's where the money changes hands, so those are -- you know, those are based on meter numbers, which are constantly calibrated.

The recoverable reserves are based on decline curve analysis. I suppose that any reservoir engineer is going to come up with a slightly different answer, but there will be a limited range of uncertainty around that number.

The original gas in place, on the other hand, probably should be considered to have the greatest potential uncertainty. That number is based on log calculations, but it can be validated by a material balance.

And for doing that, we would use the production data that we referred to earlier, along with pressure data, which we have two sources for, which would include a first delivery pressure, which is a wellhead pressure obtained just prior to turning the well to sales. That data is somewhat problematic in that it's a commingled pressure measured at the wellhead, without any particular QC as to whether the well is fully built up or there might be some remaining load in the hole, et cetera.

In addition to that, we have layer pressure tests that we've obtained by lowering cast-iron bridge plugs with gauges below them in order to isolate each layer after perforating and before frac'ing, and then measuring a falloff for two to three weeks prior to completing the wells, and we consider that to be very high-quality data.

Q. Is the pilot designed in such a way that you'll obtain data that will help you resolve some of these problems?

A. Yes, we will use pressure observation wells in order to record pressure on the layers over time, in addition to further layer pressure testing on the new pilot wells.

Q. Let's turn to the information behind Tab 11 and talk about the Dakota layer pressures.

A. Right, this part of the presentation is looking at the validation of the log volumes using the pressure data, and this first slide is showing firstly, on the right, a pressure that we derived from the first delivery pressure from the initial drilling campaign of the Dakota, showing an initial reservoir pressure slightly over 3300 pounds.

The other data is -- the layer pressure data on the Twowells, Cubero and lower Cubero, from four different wells in the unit, measured during 2001. And what you see is a fairly small amount of depletion differential between each layer and slightly differential between the wells.

Q. The letters on the far left are a code for what?

A. For the layers of the Dakota, the Twowells, the Cubero and the lower Cubero.

Q. TWLS is what?

A. Twowells. CBRO is Cubero.

Q. The Application requests approval of two pressure observation wells?

A. That's correct.

Q. And you want approval of both of them?

A. We would like approval of both of them. In fact, today we are contemplating the possibility of dropping one of them.

Q. You don't know which one to drop at this point?

A. More than likely we would drop the first one, the one that is labeled in the exhibits as POW 1.

Q. The plan now is to seek the Examiner's approval of both of them?

A. Yes, sir.

Q. And what would be the basis for having two, as opposed to one?

A. The original idea behind the POW wells, in addition to monitoring pressure decline and validating volumetrics, was also to obtain interference test data that might help us to evaluate permeability anisotropy. The modeling work that we've done so far suggests that the results of that testing may be somewhat ambiguous, and so we are hesitant to spend the money that it takes to obtain that data, knowing that it could be ambiguous.

Q. What is the potential capital investment for the additional wells?

A. Each POW well is expected to cost in excess of $2 million, with no return other than information.

Q. So your request, then, is to have both of these approved in this Application, and then you may select from those, whether you drill them both or just use one or the other?

A. That's correct.

Q. Turning to the next slide, you've got some pressure decline plots here. What are you showing?

A. What I'm showing here, these P/Z are arranged geographically with Section 8's plot in the center. We are looking from the center of each section, at an 8000-foot radius around each section center, and looking at the material balance data around that, around that point.

The blue points represent first delivery data, and these little yellow triangles represent pore-volume-weighted average pressures from the layer pressure tests.

Q. Why are you looking at this slide?

A. The purpose of this slide is to check the log calculations versus the material balance data. If I -- the pink lines, then, are actually constructed from logs and initial pressures independent of the current pressure measurements.

What we see here is that not only the first delivery pressure data, but also the very high quality layer pressure data, falls almost exactly on the lines and in our minds validates our log calculations.

And we have -- I'm sorry they're so small, but you see there's two data points in Section 16, another data point in Section 18, and then in fact another one in Section 19, just out of the area, all of them following very close to the lines constructed from the log data.

Q. This, then, allows you to validate the log data?

A. Yeah, we feel that this validates the log volume interpretation.

Q. Do you also use this information in your simulation?

A. Yes.

Q. Let's turn to Slide 12 and talk about the Mesaverde volumetrics.

A. Right, the Mesaverde volumetrics are less straightforward. There's two problems that we deal with in the Mesaverde that we don't see in the Dakota. The first is multiple pressure gradients, and the second is a non-marine unit called Menefee that has problems with sand continuity.

Q. Let's look at the next slide.

A. This slide, up in the upper left we see a Basin locator map. The Basin is indicated by this red outline here, and cutting the Basin is a black line which is the line of section displayed by the main picture to the right.

Q. As we look at the main picture, then, the far right would be the north side of the line?

A. Right.

Q. And then the far left would be the south side of the line as that diagonal line is placed on the locator?

A. That's correct.

Q. When we look, then, at the big display, project for us approximately where we would find in this sequence, geologic sequence, Section 8.

A. Section 8 would occur someplace in here. If you look at the locator map, 27-and-5 is to the east of this line of section, but if we project onto the line of section it would be somewhere in this area.

Q. And for the record, then, you're down looking at the Menefee, you're moving to the right on the Menefee as it pinches out, and just to the top there's the Cliffhouse?

A. That's correct.

Q. You see the "C" in Cliffhouse? If we draw a vertical line starting with the C and go up and down, that would be the approximate location of Section 8?

A. Yeah, thank you.

Q. What is that -- How are you going to deal with that as a reservoir engineer?

A. Okay, this slide depicts, if you will -- the non-marine units are displayed by orange, the marine sandstones are displayed in yellow, and then the marine shales are displayed in blue.

And if we look at the Dakota down at the base of the section, we see the Dakota sand separated by thin marine shales.

Conversely, in the Mesaverde we see the thick marine sands separated by a very thick non-marine shale. So that while the Dakota gas appears to have a common initial pressure gradient between layers, we have a situation in the Mesaverde where it's suggested that the same assumption may not be valid.

Q. So what do you do?

A. Well, we look at the data.

Q. And how would you look at the data?

A. This first slide following that display is looking at the first delivery pressures from the first drilling campaign of the Mesaverde, which we took to be 1949 to 1959, and we've posted those pressures against the TM "X" coordinate, or the easting.

So we can look at this data now from west to east across the Basin, and we see a fairly consistent trend indicating initial bottomhole pressures in the west of maybe 1250 pounds, gradually grading to maybe 1300 pounds in the east.

But as we look at this data, we need to bear in mind that the typical completion over which this was measured will have commingled the Cliffhouse with the Point

Lookout, and the wellbore pressure would then be controlled by the perm contrast of those two layers and limited by the lowest-pressured layer.

So with that in mind as we look at the next slide, what we see here is that -- there's our 1300-pound line that we saw very clearly in the first delivery pressure data from 1949 to 1959. And posted as well on this chart is layer pressure data gathered in 2005 and 2006 that shows a Cliffhouse depleted somewhat below that 1300-pound line, but Menefee and Point Lookout, both zones in every case, having significantly more pressure than the first delivery pressures would indicate.

The conclusion from this slide is that the pressures -- first delivery pressures in this area must have been indicating Cliffhouse initial pressures, while the Point Lookout has an initial pressure in excess of 1950 pounds.

Q. Turn to the next slide for us. You need to explain what you're doing here. What is Channel Belt Point Bar Model? What's this for?

A. Well, we're trying to understand, you know, how we have different gradients, and we're at the same time wanting to understand what to do with our Menefee volumes. And what these four displays are showing is a very simple object model looking at 20-to-1 diameter:thickness geobodies with a 10 times vertical exaggeration. And for example, you know, something very similar to what we see in Menefee outcrops, which is very thin sand lenses, on the order of a few hundred feet across, less than 10 feet thickness.

And what this illustrates is the importance of net to gross with respect to sand continuity and, more importantly, effective pore volume.

If we look at the upper left-hand display, we see a 10-percent net-to-gross model, which indicates that aside from the lenses that have been penetrated by wells, all other lenses are likely to be disconnected from those sandbodies and therefore ineffective to any development.

Q. Which one of these net-to-gross illustrations is most illustrative of the situation you find in Section 8 of 27-and-5?

A. It would be the 10-percent illustration.

Q. So then what are you going to do?

A. What we've chosen to do initially is to essentially neglect that volume and say that it is ineffective. And being ineffective, it also explains, you know, the possibility to have two gradients in the Cliffhouse and Point Lookout.

Q. Let's turn to one last slide before we take our break. If you'll finish up with the next slide.

A. Okay. What we see here is similar to the Dakota. The first thing that we notice is that the first delivery pressures fall below our calculated lines, as we would expect them to follow the Cliffhouse depletion. We then have anchored our calculated lines at the pore-volume-weighted average initial pressure from our initial analysis of the LPT data, then anchored them on the right side from our log calculation excluding the Menefee and including the Chacra 1, Chacra 2, Cliffhouse and Point Lookout.

And then finally what we see, if we look at the layer pressure data, being really the only reliable data that we can go to in this instance because of the commingling, we see in Section 6 a nearly perfect fit, as well as in Section 15. Again, a perfect fit between the material balance and the log calculations.

So the conclusion of that is that we feel very confident, with our log volume calculations, going forward.

MR. KELLAHIN: Is this a good place to stop, Mr. Examiner?

EXAMINER JONES: Yeah.

MR. BROOKS: Okay.

(Off the record)

EXAMINER JONES: 1:15 all right with you?

MR. KELLAHIN: Sure.

(Thereupon, a recess was taken at 11:53 a.m.)

(The following proceedings had at 1:25 p.m.)

EXAMINER JONES: Okay.

MR. KELLAHIN: Mr. Examiner, we'll return to the exhibit book, and we're going to start with Exhibit Tab 13 and the first display after that. You're going to be looking at a color plat that shows the pilot plan and gives you a visual illustration of the location of the pilot wells.

Q. (By Mr. Kellahin) Mr. Roberts, let's turn to the display on the screen. Identify what we're looking at.

A. This is a plat of Section 8 showing the existing wells, as well as the new pilot wells that are proposed, according to our infill pilot proposals.

Q. What's the concept for locating the wells on the surface in relation to their ultimate bottomhole location?

A. Each of the wells is drilled from an existing surface location to its bottomhole location, according to a 20-acre density.

Q. Do you have some visual illustrations to show us how this will take place?

A. Yeah.

Q. Let's turn to the next display.

A. This display is showing the typical production footprint, which impacts on the order of three acres.

Q. Next?

A. Then this would be a schematic of a drilling footprint for multiple wells on a given pad, showing the dimensions and how they would change according to how many wells we drilled upon the pad, with the possibility to drill up to five wells from the same pad. The surface impact of that drilling footprint ranges from 3 to 4.7 acres, depending on how many wells we drill.

Q. Next?

A. And then this would -- this next slide shows the ultimate final production footprint, scaled according to the number of wells with the surface impact ranging between 3 and 5.4 acres for the final production footprint.

Q. Do you have a display that illustrates the magnitude of surface disturbance?

A. Yes, this next display shows an estimated current production footprint of about 28 acres. Our expected footprint at the conclusion of our drilling would be on the order of 37 acres. We believe that that will have saved us from impacting about 42 acres, where straight-hole drilling would have impacted on the order of 79 acres.

Q. Let's turn to the timeline, if you'll turn to Tab 14 and look at the first slide.

A. This time line is just the highlights of the project, beginning with the unit partners' meeting back in August of 2006. We met, you see, with the BLM and NMOCD in

January, and we are on the third task in 2007, today, with seeking the pilot approval. Following that, we will wait on partner and regulatory approvals and hope to implement at least the first seven wells of the pilot during this year before wintering, and then conclude the implementation in 2008. And then we have some few years of data monitoring and simulation studies before we hope to be back here with an infill application, possibly 2010.

Q. Do you have a projection of the costs associated with the pilot?

A. Yes, we have budgeted about $34 million over two years for the pilot. About two-thirds of that is for drilling, with the remaining one-third for data acquisition, including the POW wells, spinner surveys, layer pressure tests and logs and things.

Q. Let's turn to Tab 15 and have you commence your discussion about how you're going to organize the modeling of the pilot.

A. Right, this is the third section of the presentation. We've built a preliminary model, and I will divide also this piece of the presentation into three sections where I will describe the model in general, then talk about the productivity modeling, and then conclude with some sensitivities that I've run for development sensitivities.

Q. Let's turn, then, to the next slide and have you give us the model description.

A. The model is built using a 150-foot gridding with a 50-foot local grid refinement over the pilot area. The grid is oriented 10 degrees east of north, which we believe to be parallel to the natural fracturing, as well as the present-day maximum horizontal stress.

There are eight active layers in the model, four in the Mesaverde and four in the Dakota. There are two inactive layers.

The volumetrics are gridded from log data and validated by material balance. There was a 10-percent adjustment applied to the Dakota, with no further editing done to the model.

The horizontal permeabilities were gridded from performance data, which necessitated that we input the same perm in every layer of each reservoir, subject to further editing to achieve our history match. The vertical permeabilities are set to zero on all layers.

The initial pressures on the upper Mesaverde, which comprises the Otero and the Cliffhouse sands, was set at 1312 from first delivery pressures; lower Mesaverde, which comprises only the Point Lookout, was set to 1947 from our layer pressure data; and the Dakota was initialized at 3340 pounds based on layer pressure data, as well as first delivery data.

Q. Do you have a schematic that will illustrate the model?

A. Yes, this next slide shows the model area, centered on Section 8 in 27-and-5, and there is the grid superimposed on that area.

Q. Give us an example of the type log you're using for the pilot.

A. Okay, our type log is built from Well Number 112 in the southwest corner of Section 8, and you see on the log the two Otero layers with the Cliff House below, then the Menefee and Point Lookout making up the layers of the Mesaverde piece of the model, and then the four layers of the Dakota piece of the model, Twowells, Paguate, Cubero, and lower Cubero.

Q. Do you have an illustration that imposes the location of the infill wells on the model?

A. Yes.

Q. Let's turn to that.

A. This is simply a three-dimensional view of the model, initialized with initial pressures in each zone.

Q. Do you have a display that allocates for the model the original gas in place by zone?

A. Yes, this display here shows how the original gas in place is distributed between the different layers of the model, and with all layers bearing, you know, a significant portion of the gas relative to the total, with the exception of the Paguate, which is nearly absent in this area.

Q. Let's turn to Exhibit 16 and have you describe for us how you're going to run the model.

A. In fact, this is how we manage to model the productivity. We model the stimulations around -- or at the wellbores by increasing permeabilities around the well cells in a configuration which honored the fracture half length that we derived from rate transient analysis.

We then applied global permeability multipliers to the grids in order to raise or lower the productivity to such a point that half of our wells had too much productivity, while the other half had too little.

At that point we addressed the layer pressure data by redistributing permeabilities between layers while maintaining a constant perm thickness per formation, and finally adjusted the anisotropy in the lower Cubero in order to address an interference issue with an adjacent well, or a well adjacent to the 40F.

At that point in time we went back to the model wells that had insufficient productivity, and caused them to match by applying local permeability multipliers. And the wells which had excess productivity, we caused them to match by reducing the productivity index.

Some of the challenges that we encountered during this exercise included variable productivity among the wells. In particular, we noticed that the older wells tended to lose a significant amount of productivity over time, particularly in connection with global curtailment during the 1980s.

We also noticed a number of our wells exhibiting a strong, what we take to be dual porosity effect, where they appeared to have anomalously high productivities at early times, which would diminish over time.

And then finally, current productivity matching was further complicated by loading in the field and some of the problems that we have to optimize wells under those conditions and the downtime that we occasionally experience around that problem.

Let me have you go, then, through the illustration of methods by which you have calibrated your model to deal with these various challenges.

A. This slide here shows the permeability multipliers that were applied. And you can basically assume that if you don't see a highlighted box around a well, then it didn't receive a perm multiplier but it instead received a productivity reduction. And if you compare the visibly modified wells with the non-visibly modified wells, they are more or less randomly distributed throughout the grid. And we take this to mean that while the average permeability may be accurately reflected in the grid, there is another level of heterogeneity that is at a scale that we are unable to map from well data.

Q. When you adjust the permeabilities, you're trying to make the adjustment in order to make what component of the data match known production?

A. We are trying to -- the model at this point is running on rate control, and so we impose the rate, and then we look to see whether the simulated pressure is matching the observed pressure.

Q. Next slide?

A. And this is the same display for the Dakota. And again, you see smaller local grid corrections, but still the same sort of random distribution between upward revisions and downward revisions. So again, there's a heterogeneity apparent in the field that we're not able to accurately predict. We feel like on average we will be right, but in each specific well's case we will probably be wrong.

Q. Next slide?

A. This is our layer pressure match. On the left you have our one Mesaverde data point that is close to the model. In fact, it's not actually in the model, and so the data is indicating the data from the 82N well, while the simulated line is actually from a grid cell that is closest to that well.

Then the 40F, you see the observed data and the simulated line. And in the lower Cubero, this is where we impose some anisotropy. There's a well just to the west of this well that was originally causing a large amount of depletion in the lower Cubero, and in order to rectify that we imposed a strong north-south anisotropy in order to reduce the depletion effects at this location.

In the 137F, we have a bit of a mismatch in the Twowells and Cubero. We observed large amounts of depletion north and south of this position in the model, such that with a slight change in the azimuth, or the orientation of the grid, we would have been able to match this very accurately. But given the state of the model and data at this point in time, we thought that it was not necessary to go to that trouble since there are other factors that could as easily explain these pressures.

Q. Did you calibrate your model so that it would have a history match of the performance of wells?

A. Yes.

Q. And is there a slide that illustrates that?

A. Well, these -- in fact, this slide and -- I'm sorry, this --

Q. This one here.
A. -- one as well, also illustrates the match.
Q. Lead us through the components of this one.
A. The lower red line is the production history of the well. This red line is the cumulative production history of the well. The black circles are the observed pressure points from the history, while the black line is the simulated pressure.

And what we see here is a very good match up until curtailment, which occurs here in the 1980s, at which time we appear to have lost a significant amount of productivity which we did not recover when the well was restored to full-time production, such that we were forced to reduce a productivity that had matched earlier, in order to match the current pressure data and performance of the well.
Q. The curtailment of production was caused by what?
A. Market conditions.
Q. How have you dealt with the apparent existence of a dual porosity effect in the pool?
A. The dual porosity effect that I was speaking of is illustrated in the next slide, and because the model is set up as a single porosity model, we were not able to address it in a rigorous way. And in fact, we don't see this effect on every well. You didn't see it on the

previous example.

But we do from time to time see occasions on a well that is apparently producing very normally, without any apparent problems -- in fact, the model is barely able to produce that rate at early times, while at later times it appears to have, in fact, excess productivity. So in order to make the early rate, we have to impose such a productivity that at the current time we have way too much and I'm forced to reduce the productivity in order to match the current response.

Q. You're using a single porosity model, is that what it is?

A. Yes.

Q. In your professional judgment, is that still an appropriate model to use for this type of pilot?

A. Yes, I think it is. It could result in -- on the occasions that we experience this type of behavior in the future, we would tend to be conservative in our predictions of these types of wells.

Q. Let's turn to the next slide.

A. This -- following the history-matching exercise, we turned the model on to bottomhole pressure control at the current bottomhole pressures of each of the individual wells, in order to generate this base forecast.

Q. Let's turn to the next tab, 17, and start with the development sensitivities. What's the general plan here, what are you illustrating?

A. Right, we have now a calibrated model such that it is appropriate, we feel, to look at various development scenarios, which we did by varying the development sensitivity, as well as the maximum offtake capacity from the section.

Q. Those, then, are the two variables?

A. Those are the ones that we've looked at, at this point in time. Before we did that, though, we were concerned with flux of gas from outside of the pilot area into a high density pilot, and so we had to adjust --

Q. Flux meaning what?

A. Basically by increasing the density in Section 8 to 20-acre spacings, we would create a pressure sink in this area that will pull gas from outside of the pilot area. And so in this exercise we were interested in looking at what impact full-scale development at 20 acres or 40 acres would look like, and so we didn't want to have the flux that is likely to occur during the pilot to affect these sensitivities, so we've taken some steps to eliminate that.

Q. In a layman's sense, you've modeled the Section 8 in such a way that you've eliminated this effect --

A. The ability of gas --

Q. -- along the --
A. -- to flow into it --
Q. Yeah, on the edges of --
A. -- for the purpose of these sensitivities, yes.
Q. All right, sir. Next slide.
A. As I mentioned, the variable development densities could lead to gas flux from the low- to the high-density areas, and this is my entire model. So I created a boundary around the pilot area and just carved off all the exterior grid cells and re-initialized the model on the 2007 pressure fields prior to running these sensitivities.
Q. Next?
A. This display is showing the pressure field as we interpret it today in the Mesaverde. The top two slides are the Otero 1 and 2, the Cliffhouse and the Point Lookout.
Q. As you go through the next series of slides and impose in the model a density that changes the acreage --
A. Yes.
Q. -- in the model, the color codes are going to change?
A. That's correct.
Q. In what way are we going to see those changes?
A. The colors are scaled to pressure, and what I'm going to show is the predicted Mesaverde pressures in 2057

under various densities. And what you'll see is that with each density increase there is less pressure remaining in the field in 2057, indicating that there is incremental recovery with each change in density.

Q. So on the color scales, we're going to be moving from the right towards the left?

A. That's correct.

Q. And we'll get more of the blues?

A. From high pressure to low pressure, or from red to blue.

Q. Let's see what happens under the 80-acre example. This is it?

A. This is it.

Q. And then what happens when we go to 40 acres?

A. See, when we go to 40 acres there's a lot more blue, indicating incremental recovery from the 80-acre case.

Q. And if you take the model down to 20s what happens?

A. Even more blue, indicating again an incremental recovery from the 40-acre case.

Q. Let's do the same thing in the Dakota now.

A. Here is the Dakota in 2007, with the Twowells, the Paguate, the Cubero and lower Cubero.

And here is the predicted pressures in 2057 under an 80-acre plan and a 40-acre plan and a 20-acre plan.

Q. Do you have a slide that will demonstrate this in a different format?

A. Yes, this slide here is showing the rates and cums versus time for the different density sensitivities, given a 5-million-a-day offtake capacity for the section. And you see -- to me of most interest is the differential cumulative productions over the next 50 years for the three different cases.

Q. So on this slide, our current density is 80 acres, effective?

A. Right.

Q. And so we're looking at the red line?

A. That would be the red line, indicating a recovery in 2057 of about 31 BCF.

Q. And the pilot would test the 40-acre effective density, which is the green line?

A. The green line, 40 acres indicates a recovery in 50 years of about 41 BCF, or an increment of about 10, while the 20-acre case shows an increment -- or gets up to a little over 44 or an increment of about 13 BCF.

Q. Now what happens if you increase this to 10 million?

A. 10 million, we don't see much change in the cumulative production. Still, there is incremental recovery in each case.

Q. And then at 15 million?

A. And 15 million is much the same story. We're not really able to sustain a 15-million-a-day plateau, except in the case of 20-acre density.

Q. Can the model detect for us what portion of the gas production would be accelerated recovery, as opposed to new reserves?

A. Yes, it can. It --

Q. Do you have a slide that shows us the recoveries in Section 4?

A. Yes.

Q. Come back one.

A. Come back one?

Q. Yeah, let's start with this one.

A. Well, this shows the incremental -- or the total recoveries, I should say, from which you can get the incremental recoveries. I have three cases, the 80, the 40 and the 20. They're largely the same, regardless of the offtake capacity.

You can see for the Mesaverde we would expect to recover about 48 percent of the original gas in place with an 80-acre program, as compared to 70 percent under a 40-acre development, 77 percent under a 20-acre development. That translates to 14 BCF, 20 BCF and 23 BCF for each of the developments.

The Dakota, on the other hand, we would expect about a 68-percent recovery under 80-acre density, 84 percent under 40-, and 89 percent under 20-, which translates to 16.7, 20.5 and 22 BCF, respectively.

Q. Okay. Now let's to apportionment between new gas and acceleration.

A. In the 40-acre development, we expect the new wells to recovery on the order of 2 BCF, with about 60 percent of that being new gas and the remainder being accelerated gas.

Q. And if the model is run at 40-acre well densities, what happens?

A. You mean 20-acre well densities?

Q. I'm sorry, 20. Yes, 20.

A. In that case, we expect the wells to recovery about a BCF apiece with a similar apportionment between new gas and accelerated gas.

Q. Then finally, let's turn to the composite slide that packages this all together. Help us understand what you're doing here.

A. This is looking at our preliminary development economics for the different cases that we just looked at. It assumes that wells were drilled only as needed to maintain the plateaus, that there is no midstream investment, which is important to know that in this area we typically only have between 5 and 10 million a day offtake capacity. And it assumes a 100-percent working interest with a 1/8 burden on both zones.

And what we see here is, for example, with a 5 million a day offtake capacity, the 40-acre case appears to give us the maximum net present value. If we have as much as 10 million a day offtake capacity, the 40- and the 20-acre densities are more or less the same.

If we were to have as much as 50 million a day offtake capacity, in that case the 20-acre option appears to be the superior by a couple of million dollars. But as I said, in most cases there would be some capital investment required to achieve that kind of capacity. So we have not looked into that at this point in time.

Q. Mr. Roberts, let's turn now to Tab 18 and have you summarize your conclusions.

A. To summarize everything that I've presented here this afternoon, I think we feel that the infill scoping study indicates significant areas of the Basin where additional drilling could be feasible.

We see a large overlap in the Mesaverde and Dakota potential in the southeast federal units area.

We believe that volumetric and decline analyses in 27-and-5 indicate poor recoveries in both reservoirs under the current development plan.

And we propose a high-density pilot in order to evaluate optimum density under current cost and price environment.

We feel that we can drill the pilot wells from existing pads, and that will minimize the surface disturbance.

And at this point in time our preliminary modeling is indicating that the recoveries can be improved by increasing the well densities in the Mesaverde and Dakota.

MR. KELLAHIN: Mr. Chairman, that concludes -- Mr. Examiner, that concludes my examination of Mr. Roberts. We move the introduction of his Exhibits 5 through 18.

EXAMINER JONES: Exhibits 5 through 18 will be admitted into evidence.

EXAMINATION

BY EXAMINER JONES:

Q. Well, I'm really impressed with you all's presentation today.

A. Thanks.

Q. Incredible. Real classy job.

It seems like Burlington must have real integrated policy or procedures of integrating teams to -- you know, like you have the scoping and then you have the pilot and -- I mean, that's all logical, but it takes coordination, it takes a lot of management buy-in to all that.

A. Yeah, yeah. We've been at it for a while.

Q. Is Conoco integrated with this yet, ConocoPhillips?

A. Yeah. In fact, they did not have really a parallel organization to ours. Their subsurface people tended to work a few weeks ahead of the rigs, while --

Q. Okay.

A. So we were a bit unique in that respect, and they basically just let us continue to exist, so...

Q. Well, I think that's a smart move on their part, leave you guys alone and let you do your thing.

You pretty much answered a lot of my questions. The scoping -- you know, I can ask a lot of questions that probably wouldn't -- more for my benefit and David's benefit here than would really help in our decision on this, but I guess one of the -- I could narrow it down to some specifics.

To pick one section out of this whole gigantic area to concentrate on, I guess, because this is conventional gas, so you don't have to -- like a coalbed methane, you would need to spread it out to look for -- Permeability is such a great influence on the outcome of infill drilling or something, but you decided to just concentrate on one section here. And you're not worried about the scale-up after this being not as representative as it could be?

A. I think we would limit the area that we would extrapolate these results to, based on the characteristics that we feel like we've got here.

You know, the Mesaverde recoveries seem to be controlled primarily by a low permeability in this area, which, you know, is kind of restricted to the southeast federal units, while the Dakota would be limited to the particular stratigraphic environment that we have at this location, which again is limited in areal extent to more or less the southeast federal units area.

In other words, beyond that we have different stratigraphic units --

Q. Okay.

A. -- exhibiting different properties, and --

Q. Okay.

A. -- we wouldn't intend to extend beyond that limit.

Q. But you could use the same approach for --

A. Right, we -- in fact, we envision similar projects in other parts of the Basin once we get this one up and running.

Q. Yeah. I guess some specific questions, real quick, for my own...

Your model, does it turn off the production at a certain pressure from each little lens, like in the Mesaverde and the --

A. No, we just let it run with, you know, bottomhole pressure control, and if things stop contributing -- you know, as we would in the field -- I mean, we don't do any workovers to close anything.

Q. What I -- I guess that's probably it, but the models that -- does it -- is it a bottomhole model, or is it a surface? Because you're downhole commingling these wells, right?

A. Right.

Q. So you've got -- you don't have any water loading, I guess, that you're worried about?

A. We have loading problems, but that's not really included in the model.

Q. That will be handled by production?

A. Right.

Q. And the Cliffhouse is -- you had a lower pressure, but a higher permeability also; is that correct?

A. Yeah --

Q. Rather than the Point Lookout?

A. -- right.

Q. And I'm not really familiar with the Dakota and all the different -- Looks like the Paguate is non-contributory; is that right?
A. Yeah, it's basically a spaceholder --
Q. Okay.
A. -- in this case.
Q. So it's the Cubero or something that's --
A. The Cubero and the lower Cubero are the big --
Q. The big --
A. -- contributors, yeah, with some Twowells.
Q. Okay. That model you ran, is that an in-house model, or --
A. It's Eclipse.
Q. Oh, okay. Okay. So it's just gas, you just ran the gas?
A. Single-phase --
Q. Single-phase.
A. -- gas model.
Q. To go back to your scoping, though, this business about doing log analysis on so many wells, it's just incredible. Your team, I guess, your geologist or whoever your log analysts were -- must have been an incredible amount of work --
A. They work with --
Q. -- you know, to do that.

A. -- databases that include upwards of three and a half, four thousand wells, all digital data, with the tops picked on every well --

Q. Yeah.

A. -- and macros that basically process the entire batch and output, all of the reservoir parameters for mapping into mapping data sets.

Q. Oh, wow. And then you import it into your model?

A. Right.

Q. Irreducible water saturation in each of those zones, I guess, that's a big -- one of the big things for your log analysis.

A. That's tricky, yes.

Q. I mean, it can affect your results big time, so -- I like to see that you matched up your -- was it a B_{gi}/B_{gf} match you did to the logs? Is that what you were doing there, where you match the --

A. Well, the upper point was the initial pressure over initial Z factor, and the lower right point was the log-calculated pore volume times the formation volume factor.

Q. Oh, okay.

A. So it was -- you know, the conventional P/Z material balance plot is P/Z versus cum production, so at zero pressure we should have the entire original gas in place, which we can calculate from the logs --

Q. Yes.

A. -- as well as from the pressures.

Q. Yeah.

A. So we -- the pink line, if you remember, was constructed from the log calculation --

Q. Yeah.

A. -- and then the pressure data was just superimposed on that to show that the pressure data was very much in line with the log calculation.

Q. Okay, so you had a check and balance there.

A. Right.

Q. And the petrophysicists can go back and change their stuff?

A. Yeah, if I come up with a line -- you know, from his work with a line that, you know, bears no relationship to the pressure data, well then, I go back to the petrophysicist --

Q. Yeah.

A. -- and say, Hey, something's wrong here.

Q. Yeah, okay.

A. But that wasn't the case.

Q. Your abandonment pressure, does that have anything to do with this? I know gas wells will -- I guess -- by the slope of your cum plots, you don't get that much more cumulative by producing for a long, long time, and then -- so really, you know, sometime the well loads up and stops or --

A. Well, it's always going to be a function of the pipeline gathering pressure, which today is creating bottomhole pressures on the order of 350 pounds --

Q. Oh.

A. -- and for the sake -- Yeah, for the sake of this exercise, I just held that constant for the entire forecast. The reality is that they're always working to lower their line pressures, so in fact, you know, our wells should be seeing lower and lower bottomhole pressures as time goes on, and we should experience incremental recovery as a result of that.

Q. Okay.

A. But we didn't make any assumptions along those lines for this case.

Q. Okay. So your management is willing to do this pilot. Incredible costs you talked them into here, for -- just to verify your model; is that right?

A. Yeah.

Q. So you must have had to do a real sales job on your management.

A. Well, they were really in it from the beginning. I think they recognized the possibility that 80s really weren't enough, and so they were asking the question, really almost before we were looking into it ourselves, and the -- in fact, it looks -- preliminary economics on the pilot itself, even with the data-acquisition costs, it may have a slightly positive cash flow itself.

Q. Okay. I notice you're using 13 for your --

A. -- discount rate?

Q. -- interest rate, yeah.

A. That's ConocoPhillips, yeah.

Q. Your prices you use for those, I notice you use different prices, you plug in the beginning price and let it escalate with your company's predicted escalation; is that right?

A. Right.

Q. Okay.

A. Yeah, they have various price forecasts as well that they use for internal economics.

Q. Planners are always playing games with their predictions.

A. I make my predictions and they make theirs.

Q. They make theirs. Let's see here.

So you're looking at -- Well, you've got your cumulative plot, so I can look at the difference there, on that.

But your surface disturbance, I guess we ought to just touch on that. I guess that BLM was pretty concerned about -- or happy that you guys were starting out from the same --

A. Uh-huh.

Q. And that way, you don't have to put in other facilities as much either, do you? I mean --

A. Well, yeah, I guess we can hope that there will be some savings on the facilities, you know, that might offset some of the directional costs, but we haven't done that part of the engineering yet. I know that our experience at Negro Canyon, we did realize some savings by clustering our production facilities.

Q. Yeah. These wells will be S-shaped, is that --

A. Yes.

Q. -- what you're going to do? Okay. Let's see.

And you're not going to do any CO_2-sequestering in this project, I take it?

A. No.

Q. Do you own your own spinner tool? You've got $5 million for a spinner tool --

A. No.

Q. It might pay to buy one.

A. Yeah, you can get stock in the spinner tool company.

Q. Yeah, it's better to concentrate on wells.

Are you going to do a bunch of papers on this, SPE papers or anything?

A. I hadn't really thought about that.

Q. The data sharing, as far as -- you know, you guys are all ConocoPhillips, Burlington now, I guess you -- internally. And by coming, showing this, you're showing a lot, you know, here. But I think it's great that Burlington is not as tight on that as Meridian might have been in the past. That's a real advantage to having one huge company that can concentrate on a big area, instead of a bunch of little companies that are all competing. Some of the pilot projects, as Mr. Kellahin knows, that we get in here are not -- they seem to be not as much science, I should say, as what you guys are doing.

Do you look into this as kind of an open-ended thing here, to where you're looking for some kind of an order that would just enable the infill drilling in this section and -- or are you looking to come back in and show some of your results, or you don't want to do that?

A. I think what we're looking at doing here is learning what we can about the feasibility of the infilling as well as learn more about the anisotropy, in order to determine whether there's something we should be considering in the way that we lay down our pattern. And at the time that we're ready to go forward with it, we would be back to request an order.

Q. The flux -- You were talking about pulling in gas from outside. Of course, you're looking at it here as a way to really tell what's going on within this section you're working on, but there's no -- there wouldn't be any correlative-rights problems with that, I take it, because you're --

A. That --

Q. -- these are both PAs --

A. Right.

Q. -- you're out in the middle of a PA, and --

A. One of the reasons for going to Section 8, we did not want to use a section on the exterior of the unit and run into those kind of issues.

Q. Okay. This well that was interfering, it just hit a big fracture in the Dakota, was that it?

A. No, it just happens that the well is, I believe, less than 1000 feet away --

Q. Oh.

A. -- and if -- You know, the original run without anisotropy, of course, created a circular drainage pattern around that old well, that showed a large amount of interference at the new 40F location --

Q. Okay.

A. -- and in order to eliminate that and get something more consistent with our observation, I had to impose some anisotropy in that lower layer in order to make its drainage more elliptical and reduce the interference at the 40F location.

Q. Okay. I think I understood that.

As far as your locations go, I'm not sure that we have to know for this order exactly the bottomhole locations. We would know the spots, you know, the units at least.

MR. KELLAHIN: That was our concept, Mr. Examiner, is to share with you the spot, and leave it to the District to give us the specifics once we had the directional surveys ready and use their administrative process to get those approved. They're going to be at standard bottomhole locations, they're at standard surface locations.

EXAMINER JONES: Really, all of them are standard?

MR. KELLAHIN: Yeah, they're standard because of the order I gave you a while ago that gives you a 10-foot setback.

EXAMINER JONES: Okay.

MR. KELLAHIN: And so they can do it at the District when we have the rest of the details.

EXAMINER JONES: Okay.

MR. KELLAHIN: So I don't think that has to delay your decision about giving us a specific bottomhole target, as long as we have the concept approved --

EXAMINER JONES: Yeah.

MR. KELLAHIN: -- which is largely a density exception to both pools.

EXAMINER JONES: Density exception. So that's basically what you're asking for here. Okay.

And the downhole commingling will be individually done; is that it? Or --

MR. KELLAHIN: I assume that's how we'll do it. There's a well-established practice to run those through for commingling, and we'll do that when we have the data.

EXAMINER JONES: Okay, those are pre-approved.

MR. KELLAHIN: Right.

EXAMINER JONES: I have no more questions.

EXAMINATION

BY MR. BROOKS:

Q. Well, I don't have much. This was a very technical presentation, so a lot of it I didn't follow very well. But I just wanted to ask about the -- first, about the surface interference. I believe you said if you did these all as separate wells, it would take about 79 acres. And it got down to what? About 34, did you say?

A. Thirty-seven.

Q. Thirty-seven. So that's a little bit more than 50-percent, about 55-percent reduction.

How much additional drilling cost do you incur to get to that level of production?

A. Not -- I don't have that figure with me. We -- It does cost extra.

Q. I'm sure that it does. I was just curious to know what rate of efficiency you were getting there in terms of cost for the surface interference.

The other thing I -- the only other question I had was, if I understood you right, the -- and my question really is, what is your concept of how far these results project? Is this something -- you think this is a typical area that will demonstrate the use -- that the 80-acre spacing is appropriate over a much larger area, or do -- You said something about, you're going to wait and judge that at the end.

A. Without being too precise, I think, you know, that the results of this pilot should be applicable to several townships in this area. You know, this southeast federal units area that we refer to is basically from 27-and-4 up to 28-and-7, and then wee feel like that's a reasonable initial approximation of where we would extrapolate these results to.

Q. And beginning back at your -- the very first of your presentation, that a lot of the area -- a lot of the area farther away is sufficiently more fractured that you would think that that would probably not be appropriate for the higher densities?

A. There are large areas that we don't think need more drilling, but there are other areas that we would probably look at separately for possible increased density as well.

MR. BROOKS: Okay, thank you.

THE WITNESS: They would be different geologic settings that would have to stand on their own merits.

MR. BROOKS: Okay.

EXAMINER JONES: Okay, I think we've ran smooth out of questions here, so -- I really appreciate you guys coming in today.

MR. KELLAHIN: Thank you, Mr. Examiner.

THE WITNESS: Thanks.

EXAMINER JONES: With that, we'll take Case 13,888 under advisement.

And that being the last case on the docket, this docket is closed.

(Thereupon, these proceedings were concluded at 2:18 p.m.)

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. _____, heard by me on __________ .

* *

________________, Examiner
Oil Conservation Division

CERTIFICATE OF REPORTER

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

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

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

WITNESS MY HAND AND SEAL March 22nd, 2007.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 16th, 2010