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:

APPLICATION OF BURLINGTON RESOURCES OIL AND GAS COMPANY FOR APPROVAL OF A PILOT PROJECT INCLUDING UNORTHODOX WELL LOCATIONS AND AN EXCEPTION FROM THE SPECIAL RULES AND REGULATIONS FOR THE BASIN-DAKOTA GAS POOL FOR PURPOSES OF ESTABLISHING A PILOT INFILL DRILLING PROGRAM WITHIN ITS SAN JUAN 27-5 UNIT, CONSISTING OF TOWNSHIP 27 NORTH, RANGE 5 WEST, WHEREBY UP TO FOUR WELLS MAY BE DRILLED ON A STANDARD GAS PRORATION UNIT TO DETERMINE PROPER WELL DENSITY FOR DAKOTA WELLS, RIO ARRIBA COUNTY, NEW MEXICO — CASE NO. 12,508

APPLICATION OF BURLINGTON RESOURCES OIL AND GAS COMPANY FOR APPROVAL OF A PILOT PROJECT INCLUDING UNORTHODOX WELL LOCATIONS AND AN EXCEPTION FROM THE SPECIAL RULES AND REGULATIONS FOR THE BASIN-DAKOTA GAS POOL FOR PURPOSES OF ESTABLISHING A PILOT INFILL DRILLING PROGRAM WITHIN ITS CULPEPPER MARTIN PROJECT AREA, CONSISTING OF SECTIONS 1-3, 10-15 AND 22-24 TOWNSHIP 31 NORTH, RANGE 12 WEST, WHEREBY UP TO FOUR WELLS MAY BE DRILLED ON A STANDARD GAS PRORATION UNIT TO DETERMINE PROPER WELL DENSITY FOR DAKOTA WELLS, SAN JUAN COUNTY, NEW MEXICO — CASE NO. 12,509

(Consolidated)

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: DAVID R. CATANACH, Hearing Examiner

October 19th, 2000
Santa Fe, New Mexico

ORIGINAL

* * *

This matter came on for hearing before the New Mexico Oil Conservation Division, DAVID R. CATANACH, Hearing Examiner on Thursday, October 19th, 2000, 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.

* * *

I N D E X

October 19th, 2000
Examiner Hearing
CASE NOS. 12,508 and 12,509 (Consolidated)

(Continued...)

APPLICANT'S WITNESSES (Continued):

* * *

E X H I B I T S

Applicant's (Case 12,508)	Identified	Admitted
Exhibit 1	14	27
Exhibit 2	14	27
Exhibit 3	-	27
Exhibit 4	40, 86	63
Exhibit 5	54	63
Exhibit 6	54	63
Exhibit 7	84	96
Exhibit 8	88	96
Exhibit 9	104	115

Applicant's (Case 12,509)	Identified	Admitted
Exhibit 1	18	27
Exhibit 2	19	27
Exhibit 3	22	27
Exhibit 4	40	63
Exhibit 5	62	63
Exhibit 6	63	63
Exhibit 7	90	96
Exhibit 8	90	96
Exhibit 9	112	115

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A P P E A R A N C E S

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FOR WILLIAMS PRODUCTION COMPANY:

SUE GRIFFIN
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ALSO PRESENT:

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

WAYNE TOWNSEND
and
RUBEN SANCHEZ
Bureau of Land Management
Farmington Field Office

MARC SHANNON
Engineer
Conoco, Inc.
Houston, Texas

* * *

WHEREUPON, the following proceedings were had at 8:44 a.m.:

EXAMINER CATANACH: All right, at this time we'll call Case 12,508, which is the Application of Burlington Resources Oil and Gas Company for approval of a pilot project including unorthodox well locations and an exception from the special rules and regulations for the Basin-Dakota Gas Pool for purposes of establishing a pilot infill drilling program within its San Juan 27-5 Unit, consisting of Township 27 North, Range 5 West, whereby up to four wells may be drilled on a standard gas proration unit to determine proper well density for Dakota wells, Rio Arriba County, New Mexico.

Call for appearances in this case.

MR. KELLAHIN: Mr. Examiner, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin, appearing on behalf of the Applicant.

EXAMINER CATANACH: Call for additional appearances.

MR. CARR: May it please the Examiner, my name is William F. Carr with the Santa Fe law firm Campbell, Carr, Berge and Sheridan. We represent BP Amoco. We are not in opposition to the Application. We do have a statement that we would like to present at the appropriate time.

EXAMINER CATANACH: Additional appearances?

MR. TOWNSEND: I'm Wayne Townsend with the Bureau of Land Management from the Farmington Field Office. We have some statements to make at the conclusion of both Case 12,508 and 12,509. We have statements concerning the technical, and Mr. Ruben Sanchez will make statements concerning surface concerns.

EXAMINER CATANACH: Thank you, Mr. Townsend.

Additional appearances?

MS. GRIFFIN: Sue Griffin, counsel for Williams Production Company, in support of Burlington's Application.

EXAMINER CATANACH: I'm sorry, Miss Griffin, on behalf of who?

MS. GRIFFIN: Williams Production Company.

EXAMINER CATANACH: Okay. Yes, sir?

MR. SHANNON: Yes, I'm Marc Shannon with Conoco, Houston, Texas. We're also here to support Burlington's Application.

EXAMINER CATANACH: Your last name, sir, is -- ?

MR. SHANNON: Shannon.

EXAMINER CATANACH: Shannon.

MR. SHANNON: Yes, sir.

EXAMINER CATANACH: Any additional appearances.

Okay, will the witnesses --

MR. KELLAHIN: May I ask you a procedural item, Mr. Examiner?

EXAMINER CATANACH: Yes, sir.

MR. KELLAHIN: We're going to try to expedite our presentation if possible, and with your permission we would like to incorporate for purposes of presentation the subsequent case, which deals with the same technical concepts. It is for a pilot area in what Burlington calls the Culpepper Martin. We believe it is possible to make a consolidated presentation. If you prefer to have them separate, we can also do that.

EXAMINER CATANACH: If it expedites this process, I would prefer it be consolidated, Mr. Kellahin.

MR. KELLAHIN: Let's consolidate it, Mr. Examiner.

EXAMINER CATANACH: At this time I'll call Case 12,509, the Application of Burlington Resources Oil and Gas Company for approval of a pilot project including unorthodox well locations and an exception from the special rules and regulations for the Basin-Dakota Gas Pool for purposes of establishing a pilot infill drilling program within its Culpepper Martin Project Area, consisting of Sections 1-3, 10-15 and 22-24, Township 31 North, Range 12 West, whereby up to four wells may be drilled on a standard gas proration unit to determine proper well density for Dakota wells, San Juan County, New Mexico.

Any additional appearances in either of these cases?

MR. KELLAHIN: Without objection, then, Mr. Examiner, we recognize that the appearances made in the first case also apply to the second case.

We're ready to have our four witnesses sworn, Mr. Examiner.

EXAMINER CATANACH: Will the witnesses please stand to be sworn in?

(Thereupon, the witnesses were sworn.)

MR. KELLAHIN: Mr. Alexander, would you distribute the exhibit books, please?

May it please the Examiner, Mr. Examiner, we have presented to you two exhibit books. Each stands alone as to separate cases. The white binder represents the federal unit, the San Juan 27-and-5 Unit. The black binder is the Culpepper Martin area.

In addition, because those project area maps are 8 1/2 by 11 in the exhibit book, we have provided you enlarged copies of each of those locator maps so that you would have an opportunity to more easily see how this project is organized.

Procedurally, for the San Juan 27-and-5 Unit, we're seeking approval to conduct a pilot project to study well density in the Basin-Dakota Gas Pool. For the 27-and-5 Unit, that initial phase of study includes eight wells, five of which are at unorthodox well locations.

In the Culpepper Martin area, that does not have the advantage of being in a federal unit. It is in what we would call a drillblock area, where all the spacing units are operated by Burlington. The Culpepper Martin area is described on the display. It deals with six wells. Originally all six were at unorthodox locations. One of those has now been relocated, and so five of the six are at unorthodox locations.

In addition to the initial approvals, we're asking you to consider the adoption of an administrative process so that if, or when, Burlington determines they have sufficient justification for an expansion of the pilot, then we might be afforded the opportunity to submit that to the Division administratively in the absence of a hearing for consideration.

If you should approve the concept of the pilot, then we recognize that if future pilot wells would be at unorthodox well locations, then we would still meet the administrative filing requirements for those locations.

However, in this presentation we're asking you to consider the opportunity to relax some of the footage setback requirements for Dakota wells that are currently applicable in the event you see merit to relaxing those locations.

Generalized, the strategy is, we're taking an area that has been developed on current well density, which is one well per 160, and we're looking for opportunities to locate pilot wells. They will, out of necessity, almost always be at unorthodox well locations, because that is where the undrained portions of the reservoir lie. In order to test that well density, the wells need to be drilled to provide additional data and to further refine the reservoir simulation studies that are being conducted.

We have four witnesses. The first is a land expert to talk to you about the notifications, the correlative-rights issues, how we propose to address those correlative-rights issues, not only externally along the boundary, but internally concerning the location exceptions.

The next witness is a geologic expert who will give you several chapters on the geology. One is a general overview of the Dakota so that you can see that kind of reservoir and how it fits for purposes of this study. We will look, then, at the geology of the specific projects and take a quick glance at that. And then he'll explain his project, the concept, and justify the locations.

We will support that with conventional engineering information so you can see from an engineering perspective what the project is outlined to accomplish.

And then finally we'll follow that up with reservoir simulation presentation, to give you a demonstration of what causes us to believe that this project is appropriate at this time.

And with your permission, we'll call our first witness.

<u>LINDA DEAN</u>,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Would you please state your name and occupation?

A. Linda Dean, land advisor with Burlington Resources Oil and Gas Company.

Q. Mrs. Dean, on prior occasions have you testified before the Division?

A. Yes, I have.

Q. As part of your employment as a petroleum landman for Burlington, are you familiar with the issues concerning the San Juan 27-and-5 Unit?

A. Yes, I have contractual and agreement knowledge relating to the federal units in the San Juan Basin.

Q. In addition, is it within your control for that unit to be able to determine who are the interest owners within the unit that share in this production?

A. Yes, it is.
Q. And as part of your responsibilities, have you been engaged to provide notification to all appropriate parties?
A. Yes, I have notified everyone that is required.
Q. Let's turn to the Culpepper Martin area. Are you also familiar with that project area?
A. Yes, I am, with the leasehold acreage and contractual obligations.
Q. And to the same extent you have determined the appropriate parties to whom notice was sent, and you sent those notices?
A. Yes, notices have been sent.
Q. Let's start with the white binder that has the San Juan 27-and-5 Unit. Are you familiar with all the land exhibits in this book?
A. Yes, I am.
Q. In addition, are you familiar with the land exhibits in the Culpepper Martin area?
A. Yes, I am.
MR. KELLAHIN: Mr. Examiner, I tender Mrs. Dean as an expert petroleum landman.
EXAMINER CATANACH: Ms. Dean is so qualified.
Q. (By Mr. Kellahin) Let's identify for the record some of the first exhibit tabs, and then we'll move quickly

into the locator maps. If you'll look at Exhibit Tab Number 1, what is the information contained behind Exhibit Tab Number 1?

A. First of all, it's the application that was dated September the 22nd regarding this case, and then behind that are the owners that were notified of this Application, and then the certified receipts that have been returned. For those that did not return the receipts, we have called them and faxed them to those owners to make sure that they are aware of this Application.

Q. Behind Exhibit Tab Number 2, what is contained behind that tab?

A. The first map is just a locator map of the San Juan Basin showing the Pictured Cliffs outcrop. The Culpepper Martin area is up in this northwest quarter of the San Juan Basin, in Township 31 North, Range 12 West. And then the other pilot project area that we want to pursue is in San Juan 27-5 Unit, down about the middle of the Basin.

Q. If you turn past this, what is the next display?

A. The next display is the San Juan 27-5 Unit. It shows the boundary in green, and then all wells that have been developed to date within this unit area, with a one-section area shown around the unit.

Q. All right, then let's turn to the next display and have you identify that.

A. Okay. The next one is also the same map, but it shows the outline of the current Dakota participating area, which is at the 24th expansion, effective November the 1st, 1973. The Dakota pilot wells underneath this project are identified in red.

There is one 40-acre tract that is not in the Dakota PA, that's in Section 3. But that's the only acreage that's not included in the Dakota participating area at this time.

Q. The Examiner has before him a large copy of the map that you're looking at right now; is that not true? He's got --

A. Yes, he does.

Q. Let me hand one of these to you too --

A. Okay.

Q. -- so that you can see it on a better scale.

On this display, Mrs. Dean, explain to me what is the significance of the area just inside the outer boundary, that's got the hachmark.

A. That is a one-half-mile buffer zone that we have placed to protect the offset ownership outside of the San Juan 27-5 Unit.

Q. And what do you mean by "protect"?

A. Well, we want to protect correlative rights for other operators for development of our pilot projects.

Q. It would avoid competition, then, with regards to increasing the current well density?

A. It shouldn't have any bearing at all, because the ownership is exactly the same, all within the unit boundary.

Q. And within the buffer area, then, that well density remains the same for current rules?

A. Yes, it does.

Q. And the well-location exceptions remain the same for the buffer area?

A. Yes, they do.

Q. All right, let's let me have you address yourself to the red squares that are shown on this display. What do those identify?

A. Those are the eight Dakota pilot infill wells that have been staked. Five of them are currently at unorthodox locations, and that's mainly due -- because of topography or fee owner request or geological reasons, which can be further explained at a later time through additional testimony.

Q. All right. Assume for a combination of all those reasons Burlington is advancing a request to have these locations approved. All but one of these -- I'm sorry, there's five of the eight are at unorthodox locations --

A. That's correct.

Q. -- in the federal unit?

A. That's correct, based upon current Dakota rules.

Q. All right. Are you satisfied that correlative rights will be protected concerning each of these unorthodox locations as they're applicable to the federal unit?

A. Yes, I do. We have actually had owner meetings with the San Juan 27-5 Unit working interest owners back on August the 29th, and we have not received any concern regarding this project at all.

Q. When we look at the unit documentation and how this fits together, is this a unit in which you have participating areas?

A. Yes, it is.

Q. For a participating area for the Dakota, is that area consistent with the boundaries of the federal unit, with the exception of this open 40-acre window?

A. Yes, it includes everything but the 40 acres, and that was due to that well being noncommercial back in 1962, which eliminated its admission into the participating area.

Q. Okay, and none of these locations are anywhere near that --

A. No.

Q. -- tract?

A. Absolutely not.

Q. Describe for the record -- I know the Examiner knows this, but describe for the record why, in your opinion, you feel correlative rights are protected within the context of the participating area in a federal unit where locations of wells are placed closer to the boundary than under current rules.

A. Okay, based upon the way that the unit participating areas work in the units, all the acreage is allocated based upon leasehold ownership, divided by the total number of acres within the unit. So they're going to have a share of every well within the unit, just based upon the structure, how participating areas work throughout the unit agreement.

Q. And there's no doubt in your mind that that's a definitive protection of correlative rights?

A. It definitely is in this situation.

Q. Let's turn to the Culpepper Martin area, and let's do that in the same fashion. If you'll take the exhibit book and start with that binder and start with Exhibit Tab Number 1, identify what is contained behind Exhibit Tab Number 1.

A. Okay. First of all, it's the Application dated September the 22nd, for the Culpepper Martin area. And it has a listing of the owners that have been contacted in regard to this Application, with the certified receipts behind it.

Again, we have contacted those owners that we didn't get evidence back that they had received and have confirmation that they do now have it. So we're confident everyone has the Application.

Q. Behind Exhibit Tab Number 2, identify the first display.

A. Again, it is the San Juan Basin locator map, which shows for this particular area the Culpepper Martin up in the northwest quarter of the Basin for Township 31 North, Range 12 West, being our pilot project area that we're pursuing.

Q. Let's focus on that area. Do you have a display -- Well, let me ask you this.

Do you have the luxury of having a federal unit in the northwestern portion of the pool that could be utilized as a pilot Dakota study area?

A. Actually, the team did several areas of interest, trying to identify an area. We do not have any federal units up in this particular part of the Basin. So we tried to find where we had control of a majority section or area of interest to go ahead and pursue this pilot project.

Q. Let's look at the next display.

A. Okay.

Q. The area outlined in blue represents what?

A. The area outlined in blue is the location that the team has identified that we want to go ahead and pursue this density project in, mainly because we are the operator of all the gas proration units within the blue outline.

Q. All right. The technical team made a technical evaluation of this area --

A. Yes, they have.

Q. -- it satisfies their criteria?

A. It did, to qualify that it works.

Q. From a land perspective, this is attractive for your purposes because of what?

A. Because we control the operating rights of all the wells that are pilot-project wells, and we know that we have the responsibility as that operator to protect the ownership. It's there within. We have control of this area as one operator and one team monitoring all of the results from the pilot project.

Q. Let's turn to the next display and look at that. This next display has also been enlarged so the Examiner could follow this in a more easily readable fashion. Let me give you a copy of this one.

A. Okay.

Q. For the Culpepper Martin project area, identify for us what is the significance of the area along the boundary that is within the hachmark.

A. We have placed a one-half mile buffer zone around our project area to protect any offset operators from our project.

Q. Let's look at the six red squares. Those represent what?

A. Those are the pilot wells that have been identified by the team that we want to do the pilot project in. And they're all interior to the half-mile buffer zone. They're all -- That's the reason this works so well, is because we actually have it interior, where we're still the operator all the way around the border of where these wells are; they're interior to it.

Q. As a result of those locations, then, there is no opportunity for correlative-rights impairments outside the project area, correct?

A. Outside the project area, that is correct.

Q. Among the population of initial pilot wells, in Section 14 there's one of these wells that was originally filed to be unorthodox, that now is standard. Can you describe for us which one that is?

A. That is correct, just as of Monday the East 7 F, which is in the west half of Section 14, has been moved to an orthodox location, so it's according to current Dakota spacing rules.

Q. The technical witnesses will talk about the appropriateness of these well locations when they testify?
A. That is correct.
Q. But from a land perspective, is there a portion of this exhibit book that contains the topographic maps that the Examiner can reference to see why these wells fit into certain topographic solutions?
A. Yes, there is. Underneath Tab 3 will be a listing or a topographical map of each location showing where they're at in relation to the drilling window.
Q. Are there federal leases contained within gas proration units adjoining wells that will be proposed at unorthodox locations?
A. Yes.
Q. Have you met with the Bureau of Land Management concerning not only this project but with the proposal to place certain of these wells at unorthodox locations?
A. Yes, we have. On October the 12th, we met with the BLM regarding potential drainage situations and have received a letter which we're willing to abide and satisfy the requirements under.
Q. It has to do with the BLM standard requirements with regards to dealing with the issues of potential uncompensated drainage from wells that are at unorthodox locations?

A. Yes, because there is a mixture of different types of mineral ownership within this project area.

Q. In addition, there are overriding royalty owners that would have differences of position concerning those wells, are there not?

A. Yes, there is.

Q. And for those overriding royalty owners, Burlington is the lessee?

A. Yes.

Q. Or at least the current lessee --

A. Yes.

Q. -- that's responsible for operations?

A. We control the operating rights and capabilities of responsibility relating to those overriding royalty owners.

Q. From a land perspective are you satisfied that correlative rights will be adequately protected if the Division Examiner approves the unorthodox locations being requested?

A. Yes, I am.

Q. And why do you hold that belief?

A. We see it as our responsibility as the operator of this area to protect the correlative rights, and our leasehold obligations require it, so we will monitor and make sure that if any offsetting wells are required, that we will take care of that.

Q. All right. For example, as the common operator, then, you drill the unorthodox location, and you're crowding an offsetting spacing unit that you also operate. Because you're the common operator, will that afford Burlington the opportunity to study and determine whether you need to take action concerning the encroaching well?

A. Oh, definitely.

Q. And Culpepper Martin provides you that opportunity because you are the operator and control those leases?

A. Correct.

Q. With regards to the Division notice requirements, have you satisfied the notice requirements for obtaining approval for wells at unorthodox well locations? You have, have you not?

A. Yes, we have.

Q. Those rules do not require you to notify royalty or overriding royalty owners, do they?

A. Underneath Rule 1207 it does not.

Q. In addition to meeting with the Bureau of Land Management, have you met with any of the other regulators or government entities concerning this project?

A. Yes, we have. We had a meeting with the New Mexico Oil Conservation Division Aztec Office back on

October the 4th regarding the technical merits of this project.

Q. What is your understanding of the BLM position concerning the appropriateness of the pilot project itself?

A. It's my understanding they are in support of it.

Q. When we look at the Culpepper -- Well, let's stay with the Culpepper Martin book, the black book. If you turn behind Exhibit Tab Number 3 there is a drilling window display, and behind that is the specific topographic exception justification?

A. Correct, correct.

Q. All right. Let's look at the drilling window map for a moment, to see if I understand what the rules are. The current rules on this display show a drilling window?

A. Yes, they do. They show a drilling window currently that is 660 feet from the quarter section line.

Q. Prior to making that rule change, the prior Dakota rules afforded an opportunity to encroach on the interior 40-acre common line in the spacing unit, and that allowed you to be 130 feet, I believe, from the quarter-quarter line, was it?

A. That is correct.

Q. The rule was changed last year, and that area of standard location has been shrunk in that dimension, has it not?

A. Yes, it has.

Q. You now have to maintain a 660 setback from that interior line?

A. From any quarter line.

Q. Okay. Is that what's illustrated on this display?

A. Yes, it is. It's just showing what is missing from what we previously had available to us other than, you know, moving from 790 to 660.

Q. Okay, and so from a land perspective, as the technical people explore the pilot project and the location of these wells, out of necessity a large group, if not all, are going to be at locations that are not within the standard window?

A. That is correct.

Q. As a result of your mailings of notification to all the appropriate parties to be notified, have you received any objection?

A. No, we have not.

Q. As a result of your meetings with the various governmental regulators, are you aware of any objections to the pilot project?

A. No, other than concerns regarding, you know, protective drainage situations, which we've addressed.

Q. And that's a standard issue with regards to well locations anyway, that you deal with on a regular basis?

A. That is correct.

MR. KELLAHIN: Okay. That concludes, Mr. Examiner, my questions for Mrs. Dean.

We would move at this time the introduction in each exhibit book of exhibit packages from 1 through.

EXAMINER CATANACH: 1 through 3 from each exhibit packet will be admitted as evidence.

Are there any questions of this witness?

EXAMINATION

BY EXAMINER CATANACH:

Q. Ms. Dean --

A. Yes, sir.

Q. -- the current Dakota location requirements, are those the same in the 27-5 Unit and in the Culpepper Martin area?

A. Based upon the recent rule changes, yes, for Dakota.

Q. Okay. And that is 660 feet from the outer boundary of the GPU and 10 feet from any internal quarter-quarter section line?

A. From the quarter-section line is where it is, not from the GPU. At one time it was the gas proration unit, and now it is at the quarter line that --

Q. 660 feet from the quarter-section line?

A. Correct.

Q. And 10 feet from any internal boundary?

A. Correct.

Q. And what are you proposing today? What is going to be changed by that?

A. In the San Juan 27-5 Unit, we're actually asking for it to match up to what the Mesaverde provides where we will protect the outer boundary of the San Juan 27-5 Unit with a 660-acre [*sic*] setback. It can just be 10 feet from any internal boundary. That is the way that the rules currently read in the San Juan 27-5 Unit, the Mesaverde, so that's in our Application.

It's different in Culpepper Martin.

Q. And in Culpepper Martin you're proposing what, now?

A. Culpepper Martin is just to extend that drilling window where it's from the gas proration unit, the 660 feet instead of the quarter line, just so we can get the middle parts available to us as being a standard location. And that would also adhere and match up and be consistent with the Mesaverde rules that are in that area.

Q. Okay. Within the 27-5 Unit, that 40-acre tract is not currently sharing in any Dakota production from the unit?

A. It's actually handled on a leasehold basis, based upon what the ownership is underneath Tract 4. It was eliminated back in 1962 because it just was not as -- a prolific well as what everything else that was in the unit.

The acreage actually came in -- Let me think here. The west half of the southwest quarter came in underneath the initial expansion, due to geological inference. That happened back in 1953.

And then the northwest quarter came in underneath the first expansion due to another geological inference situation, and it wasn't until the 12th expansion that the northeast of the southwest came in.

So it was spaced out and it was all done based upon geological inference on how the Dakota participating area was being formed. And of course it just eliminated the 84 well when it just was not commercial enough to share in the production with the rest of the wells in the unit.

Q. So that 40-acre tract is not currently in a Dakota GPU?

A. Its in a Dakota GPU, and according to state spacing, you know, it carries its standard 320, but for production purposes it does not share in the unit participating area revenue.

Q. That's just paid on that --

A. It's paid based upon --

Q. -- GPU basis?

A. -- that ownership in that tract for that unit. And it's not that we couldn't maybe look into doing something about it. I know we've drilled the offset Dakota well, the 84 E, and possibly get it included. But, you know, it's been that way since 1962.

Q. The remainder of the unit, however, is in the Dakota participating area?

A. Yes, it is.

Q. Which essentially means that any Dakota well drilled, production from that well is shared by all the unit interest owners?

A. In like interest.

Q. So drilling extra wells on these GPUs is not going to affect anybody within this unit?

A. It will not.

Q. How about the Culpepper Martin? I wanted to talk to you a little bit about that.

A. Okay.

Q. Now, as I understand it, Burlington is the operator of all of that acreage in that unit -- or in that area?

A. We're the Dakota operator of everything within the project area.

Q. Now, the interest is not the same, though; is that correct?

A. There are some instances where the leases are consistent, that we have a mixture. We have 76 percent of this acreage being BLM minerals, 4 percent being state, and 20 percent being fee. And it just depends on where you're out in the unit that it changes. The lease lines are noted on the map, it shows where it changes, you know, the lease ownership. You know, sometimes they're federal to federal, but...

Q. So from proration unit to proration unit within this unit, the interests may not be common; is that correct?

A. It is not, as far as the burden owners are concerned.

Q. Now, if Burlington is drilling a well, say, in Section 10, which you, in fact, are, and say there's an offset GPU that's not the same interest ownership, how is that interest owner being protected in that acreage?

A. Well, we're looking at doing compensating wells for that proration unit. There is one that's offsetting and stuff, and we will just have to monitor. We don't expect drainage to occur for several years, and we'll get more into that in the technical presentation. But for now it would be a concern. And we recognize that concern and are willing to protect that, you know, whatever is necessary.

Q. Well, simply from the fact that you're allowed to drill three wells in that half section, and I'm in the adjacent half section and I'm only allowed two wells -- I mean, how am I protected? You may eventually drill another well.

A. Right, right. And that's just it. We'll have to monitor it for drainage to make sure we are protecting the adjacent leasehold. And out in Section 10 that all happens to be the same lease, and so it wouldn't be a problem. But you get down in Section 14, and that's where the BLM has written their letter, because there is a mixture of federal and fee ownership within those spacing units.

But we don't see that right now. It's a concern that we will take the responsibility as the operator to protect those correlative rights.

Q. Well, I guess I'm still a little confused. If you're not ultimately allowed to drill any more wells, other than the pilot wells, I mean, I don't know how you protect --

A. Well, and that's what -- the reasons we were for the project area, just so we would be able to stay within there and drill, if necessary, an offsetting well. If these wells come in, you know, at high pressures and they are seen as being draining, we can go in and offset them, because we are the operator and we do control the leasehold ownership that offsets them.

Q. So your Application is actually seeking the authority -- to have the authority to drill these additional wells?

A. Additional wells within this project area, if it's deemed necessary.

Q. Where you deem it necessary to protect correlative rights?

A. Correct.

Q. And you're going to make that determination?

A. I am not.

Q. Well, Burlington is?

A. A reservoir -- Burlington is.

MR. KELLAHIN: Well, that could be part of the administrative process that we're seeking, Mr. Examiner, so that there is Division control and review of that action. We are the common working interest owner; there is no other working interest owner. It's the royalty and overrides that are at issue.

THE WITNESS: Well, we do have working interest owners in Section 2 and Section 23 that have been contacted. They're not within our project wells, but they own interest, you know, in Section 2 and 23; we do have some joint owners in those two sections. And we have contacted all of them, and none of them have shown objection to us going ahead with this project.

Q. (By Examiner Catanach) Okay. Now, who have you notified in both these cases?

A. We have notified all of the offset operators around the area. And if we were the operator, we notified the working interest owners that we have. And then we have notified the working interest owners that we have in Section 2 and 23, and that's it. There was 11 owners total that were contacted.

Q. Okay, so you've notified in this Culpepper Martin area simply the working interest owners in Sections 2 and 23?

A. Yes.

Q. And the offset operators around the unit, around the proposed area?

A. The offset operators around the project area.

Q. Have you notified any royalty or overriding royalty interest owners?

A. No, we have not. According to Rule 1207, we currently are not required to do so.

Q. I see. Do you think that as a royalty interest owner, someone may be affected by this Application?

A. There's a possibility of it. We recognize that and are willing to protect it to the best of our ability.

Q. Ms. Dean, is that true also in the San Juan 27-5

Unit case?

A. We only contacted working interest owners and offset operators, that is true.

Q. Working interest owners.

A. And working interest owners where we're the operator, I should quantify that a little bit more, in the 27-5 Unit.

Q. I'm sorry, working interest owners?

A. Well, if we were the operator in an offsetting proration unit --

Q. Uh-huh.

A. -- we contacted the working interest owners. A lot of it is surrounded around other federal units that we operate, and so we went ahead and contacted those that were not common to the San Juan 27-5 Unit.

Q. Okay. Again, no royalty interest owners or overriding royalty interest owners notified in this case?

A. No, sir.

Q. The unorthodox locations, there is going to be testimony later on about the necessity for those; is that correct?

A. Yes, sir.

Q. And the locations that you've got listed in your advertisements for these cases, those are all correct, as far as you know, right?

A. Except for the East 7 after the Culpepper Martin project area, which has been just moved to a standard location and will not require an unorthodox approval.

Q. Do you know what the well location is for that well?

A. The current footage for it is 1510 feet from the north line, 2100 feet from the west line, Section 14, Township 31 North, Range 12 West.

Q. That's the east --

A. Yes, sir.

Q. Have you talked to anyone that has expressed any concern about your projects?

A. Other than the letter we received from the BLM regarding potential drainage, no.

EXAMINER CATANACH: Okay, that's all the questions I have.

Mr. Chavez?

MR. CHAVEZ: Mr. Examiner, Frank Chavez, Oil Conservation Division, Aztec.

EXAMINATION

BY MR. CHAVEZ:

Q. Mrs. Dean, back to the 27-5 Unit, the 40-acre nonparticipating in Section 3, is that 40 acres a single lease, a 40-acre lease?

A. We actually remit royalties and pay costs on a leasehold-type basis, so it really does kind of stand alone. I mean, it has a 320-acre proration unit, but the acreage does not contribute to the participating area.

Q. But is that 40 acres an individual lease?

A. Yes, it is the same, same lease.

Q. What is the -- Is the rest of the 320 acres of that 280 acres a separate lease?

A. No, it's the same lease. The whole Tract 4 is within Section 3, and it's all the same lease.

Q. Okay, the formula, then, for nonparticipation is only for the 40 acres that the well is located on?

A. Actually, in our system we show that it has a 320-acre spacing unit. For state purposes it is 320 acres, but for disbursement of revenue and cost, we handle it on the leasehold basis.

And there's other units that this applies. You know, we've run across it as we've developed the infills and stuff where you have part of the dedicated acreage; it just has not been included because of it having a noncommercial well, just not coming in because the geology did not prove it up to come in.

Q. So the leasehold and working interest in that 40 and in the rest of the 320 are all the same?

A. Yes.

Q. Okay.

A. Yes.

MR. CHAVEZ: That's all.

EXAMINER CATANACH: Any further questions?

This witness may be excused.

WILLIAM BABCOCK,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. All right, sir, would you please state your name and occupation?

A. My name is William Babcock. I'm a petroleum geologist for Burlington Resources in Farmington, New Mexico.

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

A. Yes, I have.

Q. Has it been your responsibilities to participate on the Burlington team for this project as a petroleum geologist?

A. Yes.

Q. And have you studied the geology for both of the project areas?

A. Yes, I have.

Q. In doing so, do you have a comprehensive understanding of the Basin-Dakota Gas Pool?

A. Yes, I do.

Q. As part of your presentation, do you have a portion of the exhibit book to demonstrate to the Examiner the current thinking about the Dakota Pool? And then we can be specific as to why you've chosen these two project areas. Are you able to do those kind of things?

A. Yes, I am.

MR. KELLAHIN: We tender Mr. Babcock as an expert petroleum geologist.

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Kellahin) Let's start with the 27-5 exhibit book, just so that we're looking at the same book. For all intents and purposes -- it's the white binder -- are the geologic displays in each book the same, with the exception that when you got to a specific project area you duplicated in an enlarged fashion the geology for the project?

A. Yes, all the displays under Tab Number 4 are the same for both project areas.

Q. And when we get, then, to the subsequent tabs, you have made them unique as to the project?

A. That is correct.

Q. Let's start with Exhibit Tab Number 4. The threshold question, I think, Mr. Babcock, is, why as a geologist are you recommending the Division approve the Culpepper Martin area and the San Juan 27-and-5 area? Is there geologic reasons that support that?

A. Yes, there are.

Q. If we look at one of these maps, what is the first, best map to look at that helps you illustrate for the Examiner those reasons? First of all for the Culpepper Martin area, why is that useful as a project area?

A. Several reasons why we want to test the Culpepper Martin area, which as you can see in the first map, under Exhibit Number 4, is up in the northwesternmost portion of the map area, and this is in contrast to our San Juan 27-5 pilot, which is in the southeasternmost portion of the pilot area.

Q. When I take this map, I'm looking at what you've described as a Dakota formation EUR map?

A. That's correct.

Q. Tell me how you prepared this and what it means.

A. This map is where we've posted all of the individual wells within the Dakota Pool, the EUR values for those wells, which is the estimated ultimate recovery from the wells, based on decline curve analysis. We've contoured that data and created this map, and that is contoured, on an average, over about one-section grid increments.

Q. That would be the estimated ultimate gas recovery for all wells, including the parent and the parent and the first infill?

A. That is correct.

Q. And you've displayed it on this map?

A. Yes, I have.

Q. How do I read and understand the color coding?

A. Okay, what this map is showing is, the contour interval lines are 1-billion-cubic-foot intervals. The contrast -- The specific values are difficult to read here, but the contrast between the blue and the green is the 1-BCF contour line. So in the blue areas, the wells in that area recovered or are expected to recover somewhat less than 1 BCF. As you get into the darker greens up to the yellow, the EURs for those areas increase.

Q. Can you use this map in this conclusion to give us an explanation of some of your reasons why you've chosen Culpepper in the 27 and 5?

A. This map is an excellent place to start along that reasoning. Would you like me to pursue this?

Q. Yes, sir.

A. The basic concept of this map is, it's pretty clear that there are two large producing areas in the San Juan Basin-Dakota Pool.

In the southwestern portion of the pool there's a large trend with some elongated streaks coming out of that blob, and those streaks extend to the southwest.

In the southeasternmost portion of the map there's another large producing trend, and that trend is where two of the existing pilot areas are in, both Conoco's pilot area, which has already been approved in the San Juan 28-and-7 Unit, and then the 27-and-5 Unit pilot which we are here seeking approval for.

The reasons for these two distinct trends in production are very obvious when you start to look at the regional geology of the Dakota.

Q. Let's do that, Mr. Babcock. If you'll take us through a summary of the regional Dakota formation geology.

A. Okay. First of all, I'd like to point out the map is the same area as the previous map. You can see our Culpepper area pilot is outlined in the northwestern portion, and the San Juan 27-5 outline is in the southeastern portion, with the San Juan 28-and-7 Unit posted for illustration purposes.

Q. This display is labeled as "2 Wells BVHH"?

A. That is correct.

Q. What does that mean?

A. BVHH is bulk volume hydrocarbon feet. And what that means is, you take the porosity -- take an individual well within the two-wells portion -- I should back up one step.

The Dakota formation is composed of four formations, the Twowells, the Paguate, and then the lower and upper Cubero formations. In some cases the Cubero is combined into one unit.

Q. You have separate displays for each of the four intervals?

A. Yes, I do.

Q. Why have you chosen to contour on this BVHH value?

A. This is the primary step in getting to original gas in place in a zone. So when you break it down by the individual units within the Dakota, you can get coherent maps that make sense and also illustrate the depositional environments within that particular unit.

Q. Can you take each of these four maps as we go through them, identify which map you're describing, and show us a comparison between the Culpepper area and the 27-and-5, so that we can visualize or illustrate the difference?

A. Yes, I will. Starting at the top, the Twowells is the uppermost unit within the Dakota, and it is an elongated northwest-southeast-trending shoreline sandstone. The Culpepper area is along the western edge, the northwestern edge of that shoreline sandstone. The -- what we would call the net pay in that interval actually pinches out in the southwesternmost corner of our pilot area. So it is along the boundary of this Twowells unit.

The San Juan 27-5 pilot area in the southeastern portion of the map is in the heart of the Twowells trend. But when you get to the southeast portion, the Twowells actually has two sandstones comprising it, two different shoreline sandstones within the same unit, and our 27-5 Unit is in the easternmost of those shoreline sandstones.

For reference again, the 28-7 Conoco pilot is in the westernmost of those two shoreline sandstones.

If we look at the next map, which is labeled the "Paguate BVHH", you can see that this one is dominantly in the western portion of the map area, with the greatest thickness in the southwestern portion of the map. This is a deltaic system. It does have some shoreline sandstones enclosed within it, but it appears to be a fluvial-dominated deltaic system. That's why it has some fingers, I'll call them, stretching out to the north and to the northeast, and also to the southwest. Those fingers would represent fluvial systems which are supplying sand to the shorelines.

This trend is -- if you can look at the main thickness trend of this Paguate system, is where that southwesternmost productive trend was in the Dakota formation. This is a very thick, sand-rich interval. And this is the only -- As we go through the following maps you'll see that in the southwestern portion the Paguate is the only sand present down in that southwesternmost portion of the Basin.

The next map is the upper portion of the Cubero sandstone, rather limited in extent, but it's important to us in our 27-5 area because it is developed in that area. It is just marginally developed in the 28-7 area, and it is not developed at all in the Culpepper area.

The lowermost unit is called the "Lower Cubero BVHH" map, and this one is also a fluvial deltaic system, but it is translated to the east from where the Paguate system is, so that there is significant overlap of this system and the Twowells and the Upper Cubero system.

So to summarize those four maps, we have the southwesternmost portion of the area, which just has the Paguate sands present, and they are very thick in some places, which accounts for the excellent EURs. But when we move up further to the east, we see that we have overlapped Twowells, upper and lower Cubero in some places where we have all three sands present. And even in the Culpepper area we do have Paguate sands extending up into that area.

These maps are summarized in the following map, which is original gas in place. And this is calculated by simply adding together the four previous maps and then multiplying by a B_g to convert from downhole gas in place to surface gas in place.

And you can see that there is some resemblance of this map to the original EUR map, which is the first one we looked at behind this tab, but that there's a significant amount of gas in place in the southeastern portion and extending up to the northwest, as well as the fluvial deltaic system to the southwest.

Q. Mr. Babcock, take a moment and explain for the record the color scale at the bottom left of this display.

A. Okay.

Q. How do we read this scale?

A. Okay, this scale is labeled at the bottom in small letters, which are difficult to see, and I've put two points on the top, which are a little easier to see. But the contact from blue to green is where we have at least 1 BCF per 160-acre location present.

As we continue in .5-BCF contours to the right, we get up to a maximum of a little bit over 5 BCF per 160 acres, which is located in 28-6, 28-7 area.

Q. All right, you've gone through an analysis and now have a Dakota formation original-gas-in-place map. What's the next part of your process in analyzing the pool with an ultimate objective of picking project areas for the pilot? What did you do next?

A. Okay, since we were evaluating what is the proper well spacing in the Dakota, the most important piece of that is, where are we draining the most gas? Where are the original wells, the existing wells, adequately draining the reservoir?

And one way to do that is to compare EURs with gas in place. We have done that, but that will be pursued -- an engineer will be showing some more detail on that.

Another way to do that is simply to look at the reservoir pressures. And in the Dakota the reservoir pressures, taken at the time the well is originally drilled, are problematic because of liquid loading. So there's a limited data set that can be used for that.

But we feel that after the original downspacing -- No, excuse me.

Q. Infill drilling?

A. -- the original infill drilling from 320 to 160 acres in the early 1980s, after that program was begun, there was a data set collected that we felt fairly confident in, which gave us this next map, which is labeled "Infill Well ISIP".

Now, I'd like to point out on this map that I have an error on my color bar at the base of the map.

Q. How do we make that correction?

A. Just cross off the numbers at the top, the two larger numbers, 1000 p.s.i. and 2000 p.s.i. Those numbers are incorrect, they've slipped across the scale in preparing this display. The bottom numbers on this color bar are correct, so that the contact from blue to green on the left side of that color bar is 1000 p.s.i., and then the contact on the right-hand side, you can see the 1750 and the 2250. It's at about 2000 pounds.

Q. That shift in labeling does not affect the validity of the map itself?

A. No, the map is still labeled correctly, and the contour values are correctly marked.

Q. How would you use this map to tell you anything about well density?

A. Well, when we -- the parent well is originally drilled and they began draining the areas, and then the increased density order, which allowed for the second well in the 320-acre drillblock, was drilled, they found a pressure. That pressure is a function of how efficiently the original well is draining that area. Lower pressures found by the second well would indicate that the original well was doing a good job of draining it. Higher pressures would indicate the original well wasn't doing as good a job.

So in particular in this map, see, in the southwestern portion of the area where we just have one sand unit present, the Paguate trend, we can see that a lot of that area is in blue, and even less in blue, implying that back in the 1980s the second well in that drillblock found pressures less than 1000 pounds, and this is contrasted with approximately 3000 pounds that the original wells found.

When you move up to the northeast on this map, the colors get lighter and lighter and you get up over 2000 pounds, to as much as 2500 pounds, indicating that the parent well was not doing a very good job of draining this area.

Q. How does this map aid you in justifying the proposal to have the Culpepper Martin project area and the 27-and-5 area?

A. Well, in looking at increasing the density for the whole pool, we recognize that these tools are imprecise so that we would need to calibrate these tools. And so we wanted to look at a range of potential drainage situations within the pool.

The San Juan 28-7 pilot that Conoco has drilled is in what we would consider to be one of the better areas in the Basin for this, or one of the most poorly drained areas by the parent wells. We wanted to start stepping down from that to look at other areas.

The San Juan 27-5 pilot seems to be a little better drained, but still with a lot of gas left in place, fairly low recovery factors.

And then to the Culpepper pilot area up in the northwest portion of the Basin, which is stepping down one more notch and still doesn't seem to be fully drained by the parent and first increased density well in the units -- or in the drillblocks, but it seems to be an area where we can recover additional gas.

And so those three pilots seem to be testing a trend which is set up by the multiple sand layers which we saw from the geological maps.

Q. Have you studied the geologic data to determine if there is a way to compare the parent well to the infill well?

A. Yes, we have.

Q. And how have you done that?

A. Well, an efficient way to do that, at least in our opinion, is to compare the EUR ratios of the two wells, which is the next display, labeled "San Juan Basin Dakota Formation EUR RATIO".

And what this is, is simply taking the EUR of the infill well and dividing that by the EUR of the parent well. So in the case of the infill well, there being no drainage by the parent well, the ratio would be -- and the infill well found the same reserves as the infill well [*sic*], the ratio would be one. And if the parent well drained almost all of the reserves, the ratio would be approaching zero.

Q. Illustrate that for me on the scale before we look at the map.

A. Okay.

Q. Can you do that on this bottom scale and describe that for me, where I am on the scale if those two events occur?

A. Once again, I have to apologize for this scale at the bottom. The numbers in this case, both the top and bottom numbers are incorrect, so I'll have to ask you to write in the appropriate numbers. And the beginning bar at the far left is .4 or 40 percent, the contact from green to yellow is 1, or 100 percent. So -- And then it's in increments of 20 percent. So .4, .6, .8 and then 1. And then my apologies for that.

Q. If I'm on the scale and I have a parent well that has been very good and has drained my spacing unit and my corresponding infill well has not been as successful, where would that put me on your color bar?

A. That's going to put you in the blue, or even farther to the left. As we see in the southwestern portion of the Basin, we're in an area where it's actually less than 40 percent, the infill well has found less than 40 percent of the reserves of the parent well.

That's in contrast to up to the northeast where the infill wells found as much as 100 percent of what the parent well found.

Q. Can you make a comparison -- You've got this comparison of the success of the infill well in relation to the parent well. Is there any way to compare or draw conclusions about how this drainage has affected your ability to effectively produce the gas in place? Could you take the gas-in-place map and compare it to the EUR-ratio map in any meaningful way? Or do they stand alone as separate displays?

A. If I understand your question correctly, you're asking me, is there a relationship between the OGIP map and the EUR map?

Q. Well, no, let me ask you this: If I have my original-gas-in-place map and I have values that show in the Conoco area and in the 27-and-5 area that there's a lot of gas in place --

A. Correct.

Q. -- and I'm looking at the EUR-ratio map, and I'm finding that the parent well has done reasonably well in some of those areas, and the infill less, is there any conclusion I should draw from that map in looking back at the gas-in-place map?

A. Yes, the conclusion is, in those cases, that the original wells are not fully draining the drillblock area, they're not fully draining the gas that is present in those areas.

Q. Do you have an explanation as to why that's not occurring?

A. Yes, there are several reasons why that's not occurring. The most basic reason is that the individual well drainage areas are less, and the areas to the northeast that you're referring to, it's because in my opinion that we have multiple zones with significant heterogeneity in those zones, both vertically, as shown in from three to four zones in particular wellbores, and laterally, because this is not as sand-rich of an area as to the southeast.

Cumulatively, we have more gas in place, but they're in many more individual sandbodies in that portion of the area, and that's why you would leave gas behind.

Q. Describe for us what you believe will be accomplished with the two pilot projects that you can't already obtain with the existing data.

A. The purpose of the pilot projects is to further calibrate our regional models. We believe that each of the sand zones acts as a separate reservoir across this Basin, particularly in the northeast portion of the Basin.

So the pilots will allow us to go into areas that we feel are the least efficiently drained in those pilots and to take reservoir pressures, determine what the existing pressure is, the average pressure of the reservoir, and also to look at zonal pressures in those areas. Those zonal pressures will allow us to more accurately calibrate our simulation models, as well as to better understand our regional gas-in-place models.

Q. Let's turn to the exhibit tab in the San Juan 27-and-5 book. Turn behind Exhibit Tab 5 and give us a short summary of why this type log is in here.

A. This is simply presented as a type log to show the zones that are present in the San Juan 27-5 area. And we can see the Twowells, the Paguate and the Cubero. In this case I have not broken down the Cubero into the upper and lower Cubero formations. This type log is presented in more of a standard, industry-accepted format.

Q. All right. Continuing behind Exhibit Tab 6, then, what is the next exhibit?

A. This is a cross-section which extends across the San Juan 27-5 Unit. The cross-section line is shown on the following, the next exhibit behind this tab. But this shows just the Dakota formation, and this has the Cubero formation broken up into the upper and lower Cubero, which is the nomenclature that we used in my maps previously. The previous type logs we just looked at is the third well in this cross-section, the San Juan 27-5 Unit Number 122.

And this shows the Twowells, Paguate, upper Cubero, which is labeled "CBRO", and then the lower Cubero, which is labeled "CBRL".

Q. And then following those, you've given him a structure map, an isopach map and a gas in place that is specific as to this project area?

A. Yes, that is correct.

Q. Any major geologic conclusions to draw from looking at those displays that affect his decision in this Application this morning?

A. No, other than that there's a lack of significant structural activity in the area, there are no major faults or significant folds in these areas that would impact drainage across the unit.

Q. Before we get into the specifics of why you have picked these wells and their location, summarize for me the geologic differences, if any, that separate out the 27-and-5 project from Conoco's 28-and-7.

A. Okay. In order to do that, it's probably best, if we could, to step back to the more regional geologic displays --

Q. Yes, sir.

A. -- behind Tab 4.

Q. Yes. Which one of those would you like us to look at?

A. Well, first I'd like to step through them once again. I'll try and do this quickly.

The Twowells, the uppermost unit, is composed of two different sand units, and you can see that in the type log, where there is two different shoreline trends, as evidenced by the coarsening upward shape to the gamma ray. But we are in the easternmost of those units, the 28-7 is in the westernmost unit. And we can skip the Paguate map because that is not present in this area and significant. It's present, but there's no sand or net pay present.

The upper Cubero formation, as we've defined net pay, it is not present in the 28-7 Unit, and there is a significant thickness of that in the 27-5 Unit.

And also, when we get into the lower Cubero, see, it is a fluvial-deltaic system. Conoco's 28-7 pilot appears to be in one channel system of that unit, and this is somewhat an amalgamation of units, but you can see the elongated northeast-southwest orientation of that yellow, extending into the 28-7 Unit.

In 27-5 it looks significantly different. So although we're calling it the same unit, there are geologic differences.

Also, if we could step back to the first display behind Tab 4 that is the EUR map, "San Juan Basin Dakota Formation EUR" map, we can see that the Conoco pilot is sort of along the edges of that southeasternmost EUR -- blob, I'll refer to it as -- and our San Juan 27-5 pilot is in the heart of that EUR trend. Where we see the most opportunity for economic increased density drilling is in this southeasternmost trend.

And we feel it's important to get a test in the center of that trend, where the EURs are a little bit higher and it's more consistently economic EURs. So we feel it is important to do another pilot area along this producing trend.

Q. Let me go to the 27-and-5 pilot. You might want to use the blown-up copy of the locator map. In the 27-and-5 Unit there is a request for the initial pilot wells distributed as we see on this display. Explain for me why as the initial wells you've chosen these wells in these locations.

A. One of the primary considerations in choosing these wells is to maximize the undrained acreage where we're putting the wells down. And since these wells are -- primary production mechanism in the Dakota formation is the natural fracture system, and those natural fractures appear to be oriented in a north-south to northeast orientation, that would give you an elliptical drainage pattern oriented like that.

So we felt that it was important to maximize the distance in the east-west direction that we can get away from the existing wells in the area.

So we also had another consideration, and that was that we were constrained by where we could put the locations by existing roads. We needed to get close to existing roads because of surface-disturbance issues.

There were also --

Q. Were you able to pick this population of wells and place them in a location that satisfied you as a geologist that they were appropriate for purposes of your technical study?

A. Yes, we were. There were some compromises made because of topographic and archeological constraints. But in general, yes, these well locations are appropriate for this study.

Q. The strategy was, again, what then?

A. The strategy was to first optimize the location based on drainage patterns, perceived drainage patterns of the existing wells. And then after that we had to accommodate surface restrictions being very limited, new surface disturbance, topographic considerations and archeological considerations on the surface.

Q. Why have you chosen an initial population of eight wells as opposed to some other number?

A. That is also a compromise. We simulated this area, and Craig will address that later but eight wells was the numbers that we used in the simulation. We felt that that was sufficient to gather enough pressure data and enough initial rate data to make us comfortable with the results from this pilot. That's our belief at this time, at least.

Q. Do you support the request to have an administrative procedure approvable by the Division for the addition of additional pilot wells or for an expansion of the pilot project in some fashion?

A. Yes, I do. We don't anticipate that we'll need more wells to evaluate our models, but there is always that possibility that we may get inconclusive results from these, so that would be the reason for seeking administrative approval for additional wells.

Q. All right. And you would request an administrative process that would allow you to submit that justification to the Division in an administrative format and obtain approval for an expansion subject to the specific well locations being approved?

A. Yes.

Q. Let's turn now to the Culpepper Martin area. Let's look at the large display for Culpepper Martin. Describe for me why the Culpepper Martin, in contrast to the 27-and-5. Why this area?

A. Geologically why, are you asking?

Q. Yes, sir.

A. This area is distinguished by a little higher drainage by the initial wells from the 27-5 area, so this is down on one end of what we consider to be the limit of economic development of the Dakota in an increased density. We look at this as probably more likely a commingled area, needs to be commingled with the Mesaverde in order to make this economic in most cases.

Q. Is part of the study team's effort to look at the opportunity for wellbores that would be economic as stand-alone Dakota wells and to also look where the Dakota is less efficiently produced, so that it is only captured by adding it in a commingled fashion with a single wellbore? Are you looking at all ranges of choices here?

A. Absolutely, and that is the reason for this pilot area, because we recognize that there are reserves in the Dakota that will only be recovered if we can commingle it with a higher zone to reduce our well cost.

Q. In the Culpepper Martin display, then, the blown-up display, describe for us why you have selected with the other team members these six wells as the initial pilot wells. What do you hope to accomplish by these locations?

A. Once again, the criteria for choosing these well locations was the same as in the 27-5 Unit. We wanted to maximize our undrilled areas with the constraints associated with surface considerations.

Q. And where possible, you've attempted to locate these pilot wells at standard locations?

A. Yes, we have, but in most cases that was difficult to do.

Q. The likely location of undrained portions of the pool will often force you to an unorthodox location, from a technical perspective?

A. Correct.

Q. Were well locations that were changed for topographic or regulatory surface issues changed so far that the no longer fit your technical objectives, or do they still meet those criteria?

A. They still do meet those criteria. We worked closely with the surveyors in locating these wells, and the BLM, in locating these wells. Some of these locations are not my first choice, but they still meet our criteria. We wouldn't be asking for them if we didn't feel that they would suit our needs in this case.

Q. Geologically, what kind of ranges of permeability are you finding in these two project areas?

A. The permeability as seen in core is very low, and -- excuse me, I have to look at my notes to -- but we find -- and this is purely of the matrix -- we find permeabilities of core at bench conditions ranging from .03 to .08 millidarcies. That's extremely low permeability. These are bench conditions, so they would be even lower in the subsurface.

The actual permeability that our wellbores see are higher than that due to the presence of natural fractures, though.

Q. Let's turn to the Culpepper Martin exhibit book, and simply for the record I'd like you to quickly go through and identify the pieces of the geologic presentation so they're clear to a reader of the transcript or to the Division Examiner.

Again, if you start with Exhibit Tab Number 4 in the Culpepper Martin book, these displays are identical to the San Juan 27-and-5 book, correct?

A. The Exhibit Number 4 displays are identical, yes.

Q. With 5 and 6, describe for us what differences we're seeing, then, in this book for the Culpepper Martin area.

A. Exhibit 5 is a type log from the Culpepper Martin area, the Richardson Number 8-E well, which is located in Section 10. And that has the same format as the previous -- as the type log in the 27-5 Unit.

The next -- Behind Exhibit Tab 6, it once again begins with a cross-section. The third well in that cross-section is once again the same as the type log, the Richardson Number 8-E, showing the correlations in the unit in our TOPS nomenclature, which we believe is the accepted sort of industry standard in this area.

The next is a Twowells structure map for the area, and showing -- also showing the cross-section location.

The next one is the upper Dakota isopach map.

And then the final one is the original gas-in-place map for that area.

MR. KELLAHIN: Mr. Examiner, that concludes my examination of Mr. Babcock. We would move the introduction of his exhibits. They're found in each book behind Exhibit Tabs 4, 5 and 6.

EXAMINER CATANACH: Exhibits 4, 5 and 6 in each of the exhibit books will be admitted as evidence.

Questions of this witness? Mr. Chavez?

EXAMINATION

BY MR. CHAVEZ:

Q. Mr. Babcock, looking at the exhibit behind Tab

Number 2 for the well locations on the 27-5 Unit -- that's the map that also shows the buffer area -- I count 11 undrilled Dakota infill locations. For example, in Section 9 this map shows only three Dakota wells and an undrilled infill location in the northwest quarter. However, next door, right next to Section 8, which is fully infilled, you have two of your pilot -- those two pilot wells.

Was there some overriding reason why the information from the pilot well would be more important there than perhaps from the infill well in Section 9?

A. Once again, we're looking at a lot of these wells as commingling candidates with the Mesaverde. And I'm backing up a step to answer your question. The wells in Section 9 are -- I can't speak specifically about that well, but in general we are holding up drilling Mesaverde wells in this area in order to commingle them with the Dakota.

I would speculate that maybe one of the reasons for drilling that -- or for holding up that well is, it's intended to be in a location that's more suitable for the Mesaverde.

The reason we are drilling two wells in Section 8 and the additional data we could recover from those wells is that because those wells are more truly in an increased density scenario, so to speak, with the fully developed area around them, so that we felt it was necessary, if we're going to drill these wells and gather pressures to assess the validity of increasing the density to more wells than four per section, we needed to do that in sections that already had four wells in most cases.

It's also in an area that we simulated, and so we needed to gather additional data in the simulation area in order to further constrain our simulation, to give us more confidence of the results moving forward from here.

But these Dakota wells in this area are -- in general, they're marginally economic, and so that would be why there are undrilled locations such as down in Section 32 and places like that.

Q. But you wouldn't anticipate getting the same kind of data from the Mesaverde-Dakota dual that you would from -- And these are intended right now as Dakota singles? Excuse me, let's ask that.

A. Yes, all of these wells will initially be drilled as Dakota stand-alones, so that we can gather pressure data and production data strictly on the Dakota with no risk of mixing up the results due to mechanical problems or whatever, if we were to complete the Mesaverde in that area.

Q. But there --

A. But that's not to rule out --

Q. Go ahead, I'm sorry.

A. That's not to rule out the possibility of commingling with the Mesaverde at a later date. In fact, it's highly likely that we would attempt to do that.

Q. Well, doesn't that same reasoning apply toward a well in the northwest of Section --

A. You probably could use that reasoning in there, yes.

Q. On your Tab Number 4, I'm trying to draw the relationship between your Twowells bulk volume hydrocarbon feet, that and your EUR map that precedes it.

A. Uh-huh.

Q. I was trying to draw some comparison, say, for example, in 28 and in 28-11, which show high EUR values but there's lower values -- your bulk volume hydrocarbon feet map. Is there -- How would you draw those --

A. Okay.

Q. -- significances? Why is there a difference there?

A. Yes.

Q. I guess I don't understand --

A. Yeah, I understand the question, I believe. I would, instead of looking at the Twowells bulk volume hydrocarbon map, I would go to the -- because in 28-10, 28-11, the primary horizon present is the Paguate, which is the next map.

So if you would look at the Paguate BVHH map, you will see that out in 28-10 we have a lot of Paguate sand. In general, it's very thick in that area. And it's also very quartz-rich, and we believe very effectively fractured in that area. And since it is one thick sand interval, that it is efficiently drained. And that's why the EURs are pretty high in that area, because you've got a thick sand that's being very efficiently drained right now.

Did that answer your question?

Q. Yes, if you go to the -- just perhaps say that generally the EUR map is perhaps a combination of the bulk volume hydrocarbon feet of the Twowells, the Paguate and the Cubero?

A. Absolutely, absolutely. The Twowells is important locally. If I could point out an example, if we go over to 26 and 6, you can see a yellow trend which is in the southeastern portion of the Basin, and that's a northwest-southeast-oriented high-productivity trend which corresponds extremely well with a very thick Twowells trend. So in that case there's almost a one-to-one correspondence with the Twowells thicknesses.

But in other areas you also have other sands which are incorporated into the original gas in place, and so the EUR map is sort of blurred by these other zones coming into the picture. So you can't just look at one of the maps.

And also, the primary driver on EUR -- Obviously gas is important, you can only recover what's there. But one of the primary factors in any tight-gas-type scenario, particularly in the San Juan Basin, is the drainage area of the existing wells. So if the existing wells are draining a larger area, you get larger EURs.

Q. And they would drain larger areas because of --

A. Natural fracturing, increased natural fracturing. And that's a combination of both lithology and tectonic activities, which are subtle in this Basin but they certainly are present.

Q. Okay, so when I would compare, for example, the original gas in place contour map with the EUR map, the differences might be due to natural fracturing, why you might have more original gas in place but lower EURs, due to less fracturing?

A. That would be my assertion, yes. I believe that is the case.

Q. Okay. To your EUR ratio contour map, I was trying to understand how you explain, then, that the ratio of one to one would indicate that the infill well will recover as much as the original well. Is that --

A. That is correct.

Q. Okay. Your conclusion that when the infill well is recovering more than the original well, you are attributing that to better what in the infill?

A. Well, this color bar at the bottom is somewhat misleading, because along the edges is where we get to where the infill well recovers more than the parent well. These are isolated instances, and where you have very limited data control, contouring techniques will tend to exaggerate an isolated instance.

So the dark red at the top, for instance, where it's got a value of actually 4, that's one well out there where the infill well happened to tap into a very extensive natural fracture system that the parent well didn't find.

In the heart of the trend where it's fully developed, you do not see anything greater than one. You see up to one in the 28-7 area, and that's about it. If I understood the question correctly?

Q. Well, you answered my understanding of it.

A. Okay.

Q. I didn't get the opportunity to look closely at the Culpepper exhibits for the wells, but is that area also -- did you look to see if there were any undrilled Dakota locations within that area?

A. In that area, when you go to the west and to the north, outside of our pilot area, you get into undrilled locations. But that is because the Dakota formation is thinning out there, and the EURs drop off abruptly and they become noneconomic. And that's why those are undeveloped to the west and also to the north, the northern half of 33 and Section 9.

We feel our buffer area effectively isolates it from those locations, though.

Q. You testified you were going to get individual formation pressures and I guess volumes also?

A. Probably not from individual zones, because in order to produce these wells you have to fracture-stimulate them. And once you've done that, you've commingled the zones, the three zones, three or four zones within the Dakota.

But we can go in and get pressures by just perforating and breaking down the cement to access the reservoir.

So we'll be able to get pressures on individual zones but not rates by individual zones. We will get rates by all the commingled zones.

Q. So your project plan is to take individual pressures?

A. On some wells, yes. Not all of the pilot wells, though. We plan on getting bottomhole pressures on all of the pilot wells, individual zonal pressures on some of the pilot wells.

Q. Do you have an idea how many is "some"? Half, a couple, one?

A. Yes, more than one. We haven't worked that out closely. We anticipate in the 27-5 area, probably three to four. Simulation is -- we need to -- We're going to be reworking our simulation in that area to evaluate how much we feel we really need, and also when we get up in the Culpepper area, probably less than that, more in the eastern portion of it, probably two wells in the Culpepper area.

Q. What would be the biggest indicate you would be looking for to call this a successful pilot?

A. High pressures, to sum it up. But to get more specific, I expect to -- I hope that we can find some of the zones, most likely the Cubero portion, would be at very high pressures.

When we take the average wellbore pressure, which is what all of our data is currently, you tend to see the lowest pressure intervals, which is the highest perm area. So by taking the zonal pressures, we hope to find that some of the zones are not being drained over 160 acres at all. And I believe that's what the results from Conoco's pilot would indicate, at least in that area.

We are hoping that we see similar results in these areas, which appear at the surface to be more efficiently drained.

Q. Can you testify as to how these wells will be completed, or will somebody else be able to do that?

A. I'm probably not qualified to do that, but I could -- Yeah, I'm probably not qualified to do that.

Q. Will there be another witness that may be?

A. Yes, I'm sure one of them could. We'll be completing these very similar to what we've completed our other Dakota wells, though. But as far as the technical details, I'm probably not the right person to ask.

MR. CHAVEZ: Okay, thank you.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Babcock, what is the ultimate goal of these two pilot projects? Looking at the big picture?

A. Uh-huh, uh-huh. The ultimate goal, in our mind, is to be able to look across the whole San Juan Basin, where the Dakota is a producing interval and define where we can recover additional reserves of any quantity, and to also define what the economics are of recovering those additional reserves. That's the answer we're looking for, is to define that across the whole Basin. We have some models in mind, and we need to calibrate that and see if we're really correct.

Does that address the question?

Q. Well, so the ultimate goal is to maybe establish infill drilling authority Basinwide in the Dakota?

A. If we feel that's appropriate, yes, absolutely.

Q. It's kind of the same approach you've taken in the Mesaverde, which you've already accomplished; is that correct?

A. That is correct, we've looked at it very similarly.

Q. The two project areas you have proposed, in addition to the Conoco project area, do you feel that's going to be representative of the whole Basin, or does Burlington have any plans for any future pilot projects?

A. Right now, we feel that we've gone in and built our regional models, and we feel that between the three pilot areas that will adequately develop what we feel is going to be economic to increase the density in.

That's not to say that other areas may not have additional reserves present, but based on our economic criteria as we see them now, this is covering what we consider to be the full range of economics, and we think this is enough data to evaluate our models.

Q. So in your opinion, these three project areas are sufficiently different in terms of various geologic and recovery parameters that they are representative, or they will be representative, for the whole Basin?

A. That is correct, that's my opinion.

Q. The four different producing intervals within the Dakota, do those exhibit similar permeability characteristics?

A. Let me first refer to the matrix permeability, which is what we determine from core. The Cubero seems to have the lowest matrix permeability and porosity. The Paguate and Twowells are somewhat variable. Based on logs, the Twowells appears to have a little bit better porosity and, I would infer, permeability, based on that, and the Paguate would be next.

Based on existing core data, the Paguate looks to be a little more permeable. I think that's because of the scattered distribution of core data. So I would say that there is a variation in matrix permeability from the Cubero to the Paguate, with Twowells having the highest porosity and permeability.

When you look at the system permeabilities, though, the Paguate trend, which is a thick, very clean, very quartz-rich sand, I believe that those attributes allow it to be more consistently fractured, and therefore its matrix permeability is probably higher. And as you remember, this is the sand trend that's in the southwestern portion of the Basin. So its system permeabilities would be higher than any of the other zones.

The Twowells has a little bit more shale in it than any of the other zones, and therefore it's probably not quite as fractured up as the Paguate trend.

Sort of a convoluted answer. I hope I answered your question.

Q. Well, do all four zones exhibit some fracture permeability?

A. I believe they do, and we have to give them higher than matrix permeabilities in order to get matches based on the simulation, so that would imply that there is some fracture component.

Q. Is any one of these intervals the more prolific zone in this area?

A. In the pilot areas, it's our belief that the Twowells is the most prolific zone and that the Cubero is a secondary contributor.

In the Culpepper it might be a toss-up between the Twowells, and as you remember there were some fingers of the Paguate which extended up into there. There may be a toss-up between those.

But we feel if we can get these wells approved and get zonal pressures, that should tell us which of those is the primary contributor in that area.

Q. Is there any structural component to these wells' drainage areas, do you think?

A. Personally, there may be some movement in the basement that is impacting some of the areas. I can't see it from structure. Many people have made attempts to do various things with structure maps, to try and predict where the natural fractures are in basins like this, and I have not seen any success except in extreme cases.

So I guess I would have to answer your question no, I don't think there is a structural component.

Q. Mr. Chavez asked you about some wells that have not been drilled in the 27-5 Unit, some 160-acre infill wells. I'm not sure you had an answer to that. Would you be able to submit something that addresses that question, why those wells may not have been drilled to this point and what the circumstances are?

A. I'm sure we can submit something. And I would agree with you, I wasn't able to give a very satisfactory answer to that question. We are in the process of drilling all of those 160-acre locations in the unit, and we've held off drilling more projects in there recently.

But yes, we can certainly submit some more documentation addressing that.

Q. The --

A. Excuse me, may I ask, would you be interested in a narrative describing that on --

Q. Sure --

A. -- regarding each location?

Q. -- that would be fine.

A. Okay, we can do that.

Q. The way that the wells were chosen within the unit, within the 27-5 Unit, the infill wells all appear to be on the west side of that unit. Is there a reason for that geologically?

A. There's not a geologic reason why we placed them there, other than that that is the area that -- We wanted to take the same approach that we took with the Mesaverde, which was to simulate a local area and try and characterize that area specifically and understand what kind of results we would get from that. So we felt it was important to put all of our wells in a concise area in order to calibrate a simulation, and to test interference patterns based on simulation results. And so that's why they're all grouped in one area.

As for why they're in that particular area, that's probably more of an arbitrary assumption. It's probably more arbitrary than anything -- We could have done it in the eastern portion of the unit as well, we just had to choose a specific area to do the study in, within the township.

Q. So do you think that the number of wells you've chosen for each of these project areas is going to be sufficient?

A. That is our intent, and that's why we chose these number of wells. We chose eight here and six in the other pilot area, primarily because of the increased risk in the other pilot area, the Culpepper Martin. That's why we didn't want to step out and drill eight wells up there. We feel the economics of stand-alone wells up there are marginal.

We hope that eight wells will be sufficient in the 27-5 area. We felt it would be. I guess we won't really know until we get the wells in the ground and can see the results. I anticipate that these will be sufficient, though.

EXAMINER CATANACH: Are there any other questions?

FURTHER EXAMINATION

BY MR. CHAVEZ:

Q. Off that question there, for eight wells in the 27-5 Unit, is there some point at which as you're drilling and getting your data you might say, Whoa, our data is such that we don't really have to drill any more wells, or that we shouldn't drill any more wells? Do you have any cutoff points like that in your plans?

A. Realistically, I suspect that we won't have that kind of data until all eight wells are drilled, to be quite honest. But if we were to drill each well individually and take the pressures and look at the completion data, I could see conceivably where we might get to six wells and say, Well, this looks good, we might want to stop. That would be a stretch, though.

When we look at a naturally fractured reservoir like this, if you look at specific areas, you find a lot of variation because of the almost randomness of fractures, at least from our knowledge base. And so we want to make sure that we have a statistically significant sampling, especially in an area as important as this.

And so I wouldn't anticipate us stopping for any reason until we have all eight wells drilled.

Q. When you say statistically significant, how many wells are statistically significant in order to get --

A. Yes.

Q. -- adequate calibration of your model?

A. That is really a judgment decision, and it's weighed by multiple factors, not all of them technical, some of them being economic as well.

Q. Did you go through that process to determine how many wells would be statistically sufficient to calibrate your model?

A. No, not in the sense of -- We didn't do multiple runs of our simulation to determine how many we needed to validate the model. I suppose there could be a technique to do that.

We looked at the Mesaverde analysis and saw how we did that, how many wells we drilled in each of those areas. And we were very happy with the results of the way those simulations turned out, and we felt that we had enough areal variation in our sampling of pressures and rates in order to adequately calibrate the whole model, the whole simulation area.

And that's really a concern, and maybe it's -- You know, statistically significant, you're probably talking 20 or 30 wells in the true statistical sense of the word. So I may have used that term incorrectly. We need enough so that we are fairly comfortable with the results that we're seeing and we're comfortable that those results are representative of the unit as a whole.

Q. What I was getting at here was a question whether or not you might be here six months from now and requesting, We need to expand our pilot because --

A. Uh-huh.

Q. -- we didn't get enough --

A. Yes.

Q. -- data to give a good statistical model.

A. Uh-huh. If I understand your question correctly, you're asking under what circumstances would we be here in six months?

Q. Well, you say the purpose was to calibrate your statistical model or your simulator?

A. Yes.

Q. And without going through the process first of how much is necessary, we wondered whether you may be actually asking for more wells than is really necessary, or too few wells at this time.

A. Uh-huh, okay. That's a difficult question to answer, because it really is -- It's a technical judgment call as to whether we have enough to be comfortable with our model.

As you know, simulation, there are -- The more data you have, the more tightly you can constrain it, the more confidence you have in that model. But at some point you have to stop and just say this is enough data.

We felt that eight wells was enough to do that, and clearly if we get clearly black-and-white answers, find very high pressures, original pressures in parts of the Cubero, in six out of the eight wells, we would probably feel that this is sufficient and we can be real comfortable going forward with this.

On the converse, if we found very low pressures in all the wells, we could probably be comfortable with what we found there too. And it's when you get in that middle ground between those two extremes, which is most likely where we'll be, that we have to make a judgment call and say, Is this enough -- Are we confident with the results we're seeing? And it's very difficult for me to quantify that right now as to what kind of results and how many more wells we might need or how many less wells we might need. It's a judgment call as to how many wells we needed.

We felt eight is a sufficient number. We've put them all in a relatively local area so that we could constrain the size of our simulation. I guess I don't know how else to answer that question.

Q. Okay, that was for 27-5 Unit. You talked about the Culpepper area as a higher risk area --

A. Yes.

Q. -- but it's also a smaller physical size area that you have to work in also?

A. Yes.

Q. So you have fewer wells there. Do the same issues apply there as we talked about with the 27-5 Unit?

A. Well, they do apply there, and the reason we're looking at less wells out there is because of the risk factors, the economic risk.

MR. CHAVEZ: Thank you.

EXAMINER CATANACH: This witness may be excused.

Mr. Kellahin?

JACK KEAN,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. All right, sir, would you please state your name and occupation?

A. My name is Jack Kean. I'm a reservoir engineer for Burlington Resources.

Q. What portion of these exhibit books are you responsible for presenting?

A. I'm responsible for Exhibits 7 and 8 in both books, and the exhibits are the same in each.

Q. On prior occasions have you testified before the Division?

A. I have not.

Q. Summarize for us your education.

A. I graduated in 1991 with a degree in petroleum engineering from Mississippi State University.

Q. Subsequent to graduation, summarize your employment.

A. I worked for Exxon Company, USA, for three years and subsequently joined Burlington Resources where I've worked for the past six years.

Q. How do you spell your last name?

A. K-e-a-n.

Q. Okay. Mr. Kean, the participation on the Burlington team by a petroleum engineer was part of your function?

A. Yes, sir.

Q. And how long have you been on this team, studying this project?

A. I've been on this team studying this project for approximately eight months.

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

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Kellahin) Let me have you turn to the exhibit book for the 27-and-5 Unit. If you'll start with Tab 7, let me have you commence with -- summarize for us what you propose as Burlington's objectives for the two pilot projects.

A. Burlington's technical objectives are threefold: To establish the economic viability of increasing the density in certain areas of the Basin-Dakota Pool; to understand where we can economically drill Dakota tails to Mesaverde wells, because that's obviously an economic and environmentally positive approach; in addition, we would like to calibrate our original gas-in-place estimates, based on data that we learn from the pilots.

We would also like to increase the confidence in our simulation in going forward and projecting three and four wells per GPU.

Q. What are the main data requirements to achieve that objective?

A. We need multi-layer bottomhole pressure in each pilot area. That will help refine the simulation. And we also would like to have, as a secondary objective, initial production rates on the increased density wells.

Q. If you will flip to the next page, let's summarize for the Examiner what is essential in your opinion as a reservoir engineer to obtain those objectives.

A. We would like to do the pilot programs in order to help reach our objectives. As Mr. Babcock mentioned earlier on, we plan to drill Dakota stand-alone wells, so that we do not confuse the issue with Mesaverde production, obtain that bottomhole pressure data and obtain that Dakota-only production.

Q. You have been part of the team that's been responsible for picking project areas, and you've chosen the Culpepper Martin area and the 27-and-5 area. What are the reasons for those two areas?

A. A couple reasons. Earlier on, Mr. Babcock showed both a pressure map and a ratio map that essentially defined a trend, or a fairway, if you will, of productive areas where we might be able to economically increase the density in the Dakota.

Culpepper and 27-5 allow us to test two opposite ends of that fairway. In addition, we will be testing pilots that are in geologically distinct areas and areas that have, or have exhibited in the past, different production characteristics.

Q. Have you and the team examined the different areas of the Basin-Dakota Pool to characterize the possible range of production that defines the Dakota in this fairway?

A. Yes, we have.

Q. Describe for us where those areas are.

A. All-righty. We probably need to turn to the next exhibit. Its first bullet is "Areas to define the Dakota". I've listed four areas, 28-10, Culpepper Martin, 27-5 and 28-7. I've placed those in order of increasing prospectiveness for increased density. That is, 27-5 and 28-7 would tend to have the highest probability of successfully being able to increase the density.

If I could, because we have not talked about 28-10 specifically yet, refer you back for a moment to Exhibit 4, the very last display, the very last display in

Exhibit 4. This is the ratio map that Mr. Babcock alluded to earlier on.

If you would, notice the location of 28-10. It is in the southwest part of the Basin, it is in area that is dominated by Paguate production. The thing that you will immediately notice is that the infill wells recovered a relatively small amount of reserves, compared to the parent wells.

So going forward in subsequent exhibits, I'm going to use 28-10 as a reference of an area where we don't feel the likelihood of being successful is as high as in other areas.

Q. Those areas would represent an opportunity to test the concept of increased density because they're likely to satisfy that criteria in terms of ultimate recovery? If the 28-and-10 area has a poor infill, the likely opportunity for increasing that density is lower, right?

A. That is correct.

Q. And as we move down the scale and look at these other three areas, conversely, the opportunity for success in a third and fourth well is increased?

A. That is correct.

Q. What are some of the reasons to increase the density that you have identified?

A. There are a number of reasons to increase the density. First is, we observed historic production increase back in the early 1980s when we went to 160-acre infill locations.

We also have observed in a number of areas high recoveries by those 160-acre infills.

We've also observed in the same areas relatively low recovery factors, which indicates that there's quite a bit of the resource left in the ground that perhaps increased density will allow us to recover.

And finally, we have reservoir simulation results in our two pilot areas that, although preliminary, do support increasing the density.

Q. Let's look at the next index tab for 8 and have you show us the comparisons of how the parent well relates to the infill well. Let's start with the 28-and-7. Describe that relationship and what you're showing on this display.

A. Yes, the graph that you see, that's labeled "28-7 Parent and Offset Infill Production" on Exhibit 8, the first one, is a plot of production as a function of time from 1970 through 1999 or 2000, and it's of the 28-and-7 area.

The light red line is a plot of the original parent wells that were drilled on 320-acre spacing.

The heavy red line is the summation of those parent wells, plus the 160-acre infills that were drilled by 1985.

For example, the 28-7 129, an original parent well will be included in the light red line, and the 129-E will be included in the heavy red line.

Q. Does this difference demonstrate that the increased density from one well per 320 to two wells per 320 was appropriate?

A. Yes, it really does. There is no evidence in this production data that the 160-acre infills interfered with the parent wells. Therefore, the incremental production that you see between those two lines is representative of additional reserves that were recovered in this period of time.

Q. Is the method utilized by you the same for each of these four areas there?

A. Yes, it is.

Q. All right, let's thumb through those and show the Examiner the relationship. We move to the 27-5. What's happened here, what's the conclusion?

A. I see the same conclusion, that the 160-acre infills did not interfere with the parent wells. And I'll also point out, notice between 28-7 and 27-5 as we thumb through these, that the production today is essentially the same as it was 30 years ago.

Q. Let's turn to the Culpepper area and look at the parent-offset relationship.

A. Again, I see the consistency in results that the 160 acres recovered incremental reserves within this time frame.

Q. And then finally the 28-and-10 relationship.

A. This is very interesting to me. Even in 28-10, which is an area that doesn't appear to have the highest increased density potential, we see the same result, that the 160-acre infills did not interfere with the parent wells.

Q. Do you have at this point an explanation for that, or is that something to be investigate and decided on later?

A. The explanation for that is a function, most likely, of an engineering equation which is governed by reservoir pressure. Wells that saw the same pressure tend to have the same flow rates.

Q. You then go to the next slide here, and you have information displayed in a different relationship. Describe for us what you're doing and what conclusion you see from the display.

A. Yes, this is a bar graph, labeled "Infill and Parent EURs Support Increased Density". For each of the areas that we just discussed, I've plotted out in red the EUR, the average EUR of the parent well, and in blue the average EUR of the infill well.

For example, in 28-10, you can see that the average parent well recovered about 4.5 B's, and the average infill recovered about a BCF. That's quite in contrast to the 28-and-7 area. You can see that that 160-acre infill recovered about 70 percent of what the parent produced.

So the conclusion that we would draw is, there's an area where there is a large difference between recovery of the parent and the recovery of the infill. That area may not be as prospective, because the parent well was relatively efficient in draining the reservoir.

On the other hand, in areas such as 27-5 and 28-7 we've reached the opposite conclusion. And you notice that Culpepper is somewhere in between. That is one of the reasons that we feel we want to do a pilot in that area, is, we need to try to define an area like Culpepper that's not clearly one or the other.

Q. The next slide, would you identify and describe this one for me?

A. Yes, once again, a bar graph, in red representing as a percentage of original gas in place what current density will allow us to recover. In blue, we're representing what we believe will not be recovered at existing density.

So once again, you see a similar story that we've seen earlier on. The 28-10, as you would expect, has a very high recovery factor under current density, whereas areas like 27-5 and 28-7 have relatively low recovery factors.

Q. Let's turn to the final display. Would you identify and describe this ratio crossplot?

A. Yes, the final display, the ratio crossplot, plots out the data that we've just been discussing.

On the Y axis, this is simply the infill-to-parent EUR ratio, the same data that we saw in the bar graph just now. On the X axis is recovery factor.

The first thing that you will notice is, there is a distinct trend that can be drawn through the four areas that we're discussing. And as you might expect, an area like 28-10 in the lower right-hand portion of the graph, because of its low infill-to-parent EUR, relatively high recovery factor, probably doesn't hold as much promise as some of the other areas.

And this also graphically demonstrates where Culpepper, once again, falls somewhat in between areas that we think have the highest potential and areas that may not hold quite as much potential.

This hopefully, as we gather data in our pilot wells, in our pilot locations, will allow us to validate this graph, to firm up these data points for 27-5, 28-7 and Culpepper, and hopefully going forward, allow us to use this somewhat as a coarse diagnostic tool in figuring out what areas have the highest potential for us to increase density.

Q. When I see the relationship between 27-and-5 and the 28-and-7, I'm drawn to the question of why don't you just wait for Conoco to finish its pilot, rely on that as the value, then, that sets the end point of the economics?

What sets the 27-and-5 apart?

A. The 27-5 is distinct geologically from 28-and-7. That is the primary reason. The second reason is, two points really don't define this relationship to the degree that would make us comfortable in using this as a diagnostic tool. The addition of 27-5 greatly increases our confidence level going forward.

Q. How long do you anticipate it will take Burlington once the project is approved by the Division to reach conclusions about your pilot project?

A. We plan to be in a position by the end of next year to validate our existing model, modify our existing model or perhaps even, depending on what we see, reject our existing model. So by the end of next year.

Q. Why have you chosen to advance the request for a pilot project now, as opposed to waiting till more or all of the Dakota infill wells that could be drilled have been drilled under current spacing?

A. There really are two reasons for that.

One is, we believe that certain increased density locations may offer superior economics to 160-acre locations.

In addition, the Mesaverde currently has different spacing rules than the Dakota, and we are -- we would like to be able to develop the Dakota along with the Mesaverde, so that we can be as efficient as possible.

Q. One of the issues the Examiner needs to address is the approval of the pilot wells that are at unorthodox location. The threshold question for him to decide is whether there is a potential drainage concern of such significant magnitude that he ought not to approve these pilot wells for you if they are not at standard locations.

When we look at these wells drilled in the Dakota, what kind of rates are you anticipating, and do you have a sense for the kind of period of time it takes to see drainage, and if so, how long, and what are we describing here?

A. Okay. Based on simulation work, which will be addressed later on, and also some additional modeling that we've done, we expect to see initial rates in terms of average monthly production on our increased density wells in the Culpepper area probably below 200 MCF a day and in the 27-5 area possibly as high as 400 MCF a day.

Q. That would be the Culpepper Martin area that I would be worried about. 27-and-5 has a higher rate. We've got a unit in place to resolve any doubts about correlative rights. But if I'm in the Culpepper Martin area?

A. Okay, in the Culpepper Martin area, once again, probably less than 200 MCF a day. Probably we'll not begin to see material acceleration until beyond ten years.

Q. And there's sufficient time, then, for Burlington to react and fulfill whatever responsibilities it has as the offsetting operator to the offending well, to determine if a protection well is needed and, if so, when and how?

A. That is correct.

Q. Summarize, then, for us in conclusion, what do you anticipate as a reservoir engineer getting from the pilot project?

A. We should get ultimately an answer to where can we economically increase the density in the Dakota, in the Dakota fairway? We'll be able to do that by gathering the pressure and the rate data from wells that are located in increased density locations.

MR. KELLAHIN: That concludes my examination, Mr

Examiner. We move the introduction of Exhibits 7 and 8 in both of the books.

EXAMINER CATANACH: Exhibits 7 and 8 will be admitted as evidence.

Questions of the witness?

Mr. Chavez?

EXAMINATION

BY MR. CHAVEZ:

Q. Mr. Kean, is there a contradiction in your Tab 8 between your 28-10 parent-offset infill graph and your volumetric recovery bar graph?

I was trying to listen to what you said there, and you said it was surprising that there was no impact, if I remembered your statement right, that there was apparently no impact to original production and that you were getting new gas in 28-10, while the bar graph doesn't seem to support that. Did I misunderstand you?

A. I'm not sure if I understand your question.

Q. I had understood you saying that in your graph of the 28-10 parent and offset infill production, the graph indicated that although it wasn't expected, it showed there was new gas being produced from the infill. However, your volumetric recoveries bar graph doesn't seem to support that that would be the case, or only for a very short period of time. Is that -- Am I interpreting that correctly?

A. I believe you are. When I originally saw the 28-and-10 graph I was a little surprised, because I knew that it was in an area where the parent wells seem to be relatively efficient. I thought that we might see some interference, but we did not, so that's why I was a little surprised when I saw this data for the first time.

Q. Did that change or cause you to question how you might be interpreting the efficiency of the parent wells and draining?

A. I don't think so. The simulation data that we have done does not show material acceleration until 10 to 20 years into the future. What's interesting about this production data is that we have 10 to 20 years of that production data, and we evidently have not seen that material acceleration yet.

So in my opinion, this actual data confirms or corroborates what we see in our simulation models.

Q. So you would anticipate, then, perhaps, in the 28-10 area sometime soon, whatever that may be, you'd see significant material acceleration then?

A. That is a distinct possibility, although I would temper that with the point that this area has a high degree of continuity. Average reservoir pressure is relatively the same across the area. Therefore, the wells should produce at pretty similar rates.

If I go to the equation Q, flow rate, equals C times reservoir pressure squared, minus the flowing bottomhole pressure squared, raised to the n -- In other words, what I'm saying is, R is common between the parents and the infills, therefore rates are probably going to be pretty similar between...

Q. In addressing those rates, did you compare well completion practices, things such as pipeline pressures in the areas or operating practices like localized compression to determine whether they may have influenced the difference in the rates that you might have seen by the different operators?

A. That is a very good question, because you might look at the bar graphs that we saw on EUR where a parent well recovered more than an infill, and then if the infill was completed in a different technique you might try to conclude that it was due to a difference in completion practice.

We did look at it and what we found is, completion fluid, that is, gel, linear gel, crosslinked versus slickwater, did not make an impact on EUR.

I base that assertion on looking at 1340 parent and infill wells. That was our universe of data. From that data set, we culled down to specific areas. We had both slickwater completions and linear gel or crosslinked gel completions, and looked at the EURs and the rates.

And what we found on a parent-to-parent basis and an infill-to-infill basis, there was no meaningful difference in EUR according to completion practice.

Q. Do you anticipate -- or have you looked at the capacities of the gathering lines in the area to determine whether or not these increased number of wells on production may require perhaps curtailing other producing wells or shutting them in, in some way?

A. Right now in the Basin, there are places of curtailment.

There are other places where the gas is able to flow without causing additional problems to other wells. But once again, I don't see that as a material issue right now for the pilots, because the rates of the wells will be relatively low.

Q. But in that particular area, in the Culpepper area and in the proposed pilot area in 27-5, do you know whether there's curtailment at this time occurring there because of pipeline or gathering-line capacities?

A. Before I'd answer that, I'd want to double-check to make absolutely sure.

MR. CHAVEZ: I think that's all I have. Thank you.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Kean, in the Culpepper Martin area you're anticipating 200-MCF-per-day increase in -- Or is that the initial producing rate of the infill well?

A. About the initial average monthly rate.

Q. Have you looked at -- Is there any way to estimate at this point how much of that will be new reserves and how much will be an accelerated-type situation?

A. Yes, sir, my colleague Craig McCracken will address that here a little bit with his simulation and show you that specifically.

Q. And when you talk about interference on your graphs, if these wells were exhibiting any interference you would normally see a decline in the parent producing rate?

A. Yes.

Q. And you're not seeing it?

A. Do not see it.

EXAMINER CATANACH: That's all I have. This witness may be excused.

MR. KELLAHIN: Just a point of clarification.

FURTHER EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Kean, Mr. Chavez was looking at this bar graph that had the volumetric recovery. It says "Support Increased Density". Do you have that display?

A. Yes, sir.

Q. Am I correct in understanding that the red portion of the display would be the volumetric recoveries attributable to the parent well and to the infill well?

A. That is correct.

Q. So when I look at the blue portion, that's the resource that remains available for investigation as to whether it will support a density greater than two wells per 320, plus some portion that may be attributable to adding wells under the current density?

A. That is correct.

Q. But at least for Culpepper 27-and-5 and 28-and-7, the magnitude of that resource that's left after current density is enough to justify going forward with the pilot project?

A. Yes, it is.

MR. KELLAHIN: All right, thank you.

FURTHER EXAMINATION

BY EXAMINER CATANACH:

Q. Are the recovery factors for these reservoirs the same in these two different areas? Are you recovering the same percentage of the original gas in place?

A. In which two areas?

A. Well, the Culpepper Martin and the San Juan 27-5?

A. It definitely appears right now that we have a higher recovery factor in the Culpepper area than we do in the 27-5.

Q. And what is that range of recovery?

A. 27-5 is around 40-percent recovery factor, while the Culpepper area is around 65 to 70 percent, based on our existing geologic model.

Q. That's quite a difference. Is that all attributed to geologic factors?

A. I believe it is.

EXAMINER CATANACH: Okay, I have nothing further.

CRAIG McCRACKEN,

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

A. Craig McCracken, reservoir engineer, Burlington Resources.

Q. Mr. McCracken, on prior occasions have you testified before the Division?

A. I have.

Q. As part of your participation in the Burlington team to study the project, you are contributing the reservoir-simulation aspects?

A. That is correct. And I should clarify, the 27-5 model was prepared under my direct supervision, and Mr. Kean and I cooperated on the preparation of the Culpepper Martin model.

Q. All right, sir. The presentation on the simulation is yours to make for both project areas?

A. Yes, it is.

MR. KELLAHIN: We tender Mr. McCracken as an expert engineer.

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Kellahin) Let's start with the 28-and-7 model, and then as we get to it we'll show the Examiner the differences and the conclusions you've reached about Culpepper Martin. But let's start with the San Juan 27-and-5 Unit.

First of all, describe for me the kind of model you've selected and why you did so.

A. The software that was used in the preparation of this model was the Eclipse software package. We chose to set this model up as a dual-porosity, dual-permeability model, where you have matrix porosity and matrix permeability, and to capture all four layers that are present in the model, in the geologic model, that is.

Q. Your first display after Exhibit Tab 9 simply summarized the model and the four layers?

A. That's correct.

Q. It then talks about a grid size. Why have you picked this particular grid size in this area?

A. It's probably illustrative to flip back two exhibits to a picture of the grid which shows that 51-by-51 grid. That's only one layer of the grid, that doesn't show all four layers. It's just the first layer.

And what this shows is that the grid is sufficient to capture an area of a significant number of wells with significant -- I'm sorry, sufficient grid cells in between wells to allow for the calculations that the model does.

Q. Okay. We've got a grid that's large enough to encompass a population of 31 existing wells.

A. That's correct, that grid is 4800 acres, and there are 31 existing producing wells within the grid.

Q. Those producing wells would include the parent and the infill well where they existed within the grid area?

A. Yes.

Q. And then for modeling purposes, you're going to introduce eight more wells to the model area?

A. That's correct.

Q. That generalizes to adding just one more well per GPU, does it not?

A. Yes, it does.

Q. So we're not investigating densities beyond the simulation of what may occur with adding -- having three wells producing in a GPU?

A. That's right.

Q. Okay. Let's go to the simulation inputs then. If you'll turn to the next page, describe for us the input values and parameters you've used.

A. The way this was done in practice was that the geological models that made up the BVHH map that you saw earlier were input directly into the simulator in digital fashion, and the simulator was then able to interpolate a value of porosity, water saturation and thickness for each of the grid cells in the reservoir model.

What I wanted to do here was just to give you a feel for what those parameters were by giving you an average for each of the zones. And as the exhibit shows, for the two wells that porosity was about 10 percent on average, 40-percent water saturation, 15-foot thickness. The Paguate was 1-percent porosity, 96-percent water saturation and 1-foot thickness. So you can see from that that that wasn't a very significant zone, which correlates to what Bill said about the Paguate in this area.

The Cubero was 9-percent porosity, 46-percent water saturated and 11-foot thick. And then the lower Cubero was 9-percent porosity, 20-percent water saturation and 25-foot thick.

I also input an initial pressure of 3085 pounds per square inch into this model for average reservoir pressure, and that was based on initial pressures from all of the parent wells averaged.

Q. Let me understand how you actually do this. Mr. McCracken -- Mr. Babcock would give you a digitized map of these geologic values?

A. That's correct.

Q. And they will be specific as to each well?

A. Yes, they will.

Q. You've not assumed a general value for porosity and applied that to all 31 wells?

A. That's correct.

Q. So it's unique in that it's been specifically identified per well, per layer?

A. Yes.

Q. Okay. You put in your pressure. What then do you do?

A. The next step is to obtain what's known as a history match, and what was varied in order to obtain this history match was essentially the operating conditions of the well, the skin, which is related to how the well is completed, and the flowing bottomhole pressure, which is related to how the wells are operated from a pipeline standpoint.

Q. For purposes of this simulation, then, the only value you're trying to match with the simulation is production?

A. That's correct.

Q. And it's gas production?

A. Yes.

Q. And the only parameters are variables that you're adjusting to make the match are what?

A. Operating conditions, essentially, flowing bottomhole pressure and skin.

Q. All right. So you're not adjusting permeability or porosity or any of those kind of things to get your match on --

A. No, permeabilities were from core.

Q. All right, so you get your model to match the existing history of production, and how confident are you about matching this parameter with this data?

A. If you'll flip to the next exhibit after the simulation grid, the way we build confidence in these models is by checking how well they match what happened in actuality, and that's what I referred to earlier as the history-match portion of the process.

And what I'm showing here is the history match on cumulative gas production versus time. The solid line represents actual data up through April of 2000, which is the date to which I did my history match. The diamonds beyond that represent a projection of just those 31 wells continuing to produce at whatever conditions they were at on April the 1st of 2000.

If you have pressure data in a process like this, that also represents a good check. Unfortunately, what we have for pressure data within this area is essentially the shut-in wellhead pressures of the infill wells at the time that they were drilled.

And the problem with shut-in wellhead pressures tends to be, if you have fluid -- and this is an area that does produce some condensate -- if you have a fluid level in the well and you don't know what it was, and you don't have any measurement of what that fluid level was, it's hard to relate a shut-in wellhead pressure to a shut-in bottomhole pressure. And in our review of our records, we had one shut-in bottomhole pressure in the San Juan 27-5 Unit on an infill well, and it was outside the grid.

Q. You get your model calibrated, you get the match, and then it forecasts future production?

A. That's correct.

Q. All right. Now you've got a model that you can introduce your eight new infill wells?

A. Yes.

Q. And you did that?

A. I did.

Q. And then you ran your model again?

A. Right.

Q. And what did you forecast?

A. The next exhibit shows a forecast of the cumulative production versus time for the 39 wells, and that's the 31 wells that originally existed, plus the eight increased density wells. And that total was roughly 66 BCF over the 30-year period of time that we ran the model for.

What the next line down, the 59 BCF, relates to is what I'm calling the base case, and that's the projection run that matches up with the graph before where there were no increased density wells drilled. The line beneath that represents the performance of those 31 wells with the eight increased density wells drilled, and that's about 56 BCF.

What I'm illustrating here is that acceleration versus unique reserves component that you brought up earlier. And --

Q. Let's make sure we have an understanding of what you're displaying. The difference that's displayed in blue represents the component of recovery attributed to rate acceleration by the introduction of the eight additional wells?

A. That's correct, and that's rate acceleration from the 31 existing wells to the eight new wells.

Q. The area in purple illustrates the additional reserves to be recovered by the eight increased density wells?

A. That's correct.

Q. And so whatever the difference is between the 66 and the 59 BCF?

A. That's correct.

Q. Just short of 7 BCF?

A. Yes.

Q. Okay. What does that tell you?

A. If you look at it on a 30-year look like we did in this analysis, the reserves that you're going to obtain from drilling an additional eight wells in this pattern is roughly one-third acceleration and two-thirds unique reserves.

Q. That makes it very attractive to consider the increased density for at least the area being simulated?

A. I would say so.

Q. Let's put this in a real-world context. Have you put some values as to cost and price of your product and forecast whether there's an economic potential associated to the recovery of this additional gas?

A. I have.

Q. Let's have you identify and describe what you've done and what you've concluded.

A. The next exhibit shows the average of the eight wells' output from the simulator. This is the rate-versus-time performance of each of those wells.

And this production forecast was then incorporated into an economic model with the parameters on the following page for cost, monthly operating costs, and an assumption for pricing. And the results that we obtained are on the right-hand column.

What this shows us is that this is a favorable project for us to pursue from an economic standpoint, and we think that it makes sense to pursue.

Q. What do you hope to achieve as a simulator by the Division approving the pilot projects for both areas?

A. As we spoke about earlier, the model right now is constrained essentially by gas production. And we would like to have a model that's constrained by gas production as well as some pressure data. And the pressure data that we're going to obtain, both in aggregate and by layer, we think will serve to constrain this model further.

Q. Once you have further constrained your model with the additional data, will you then be able to introduce wells at increased density locations to test whether it is appropriate to have densities of four more wells in a section or two more wells in a section, that kind of forecasting study?

A. Yes, we will, and we will be able to have a higher degree of confidence in those forecasts, and we'll be able to sensitize other things too, such as the placement of those wells.

Q. Okay. Let's turn now to the Culpepper Martin simulation, and let's identify those displays for the Examiner to complete your presentation.

A. The set of displays under the Culpepper Martin model follows the same pattern. So if you'll allow me, I'll highlight the differences on each of these displays with the 27-and-5.

In Culpepper, the lower Cubero interval essentially was nonexistent. So it's a three-layer model instead of a four-layer model.

The Culpepper Martin area is a little bit more elongated in the north-south direction, so our grid, instead of being a square, was a little bit more rectangular, with a 47-by-38-by-3-layer grid, and it was a bit larger to incorporate all of the wells that were in the area.

There were six increased-density wells in the Culpepper Martin model to match up with what it is we plan to do.

Some differences in the simulation inputs, you'll see that some of the porosity values are fairly similar, formation by formation, although there's a major difference in the Paguate. The Paguate is a much more significant interval and a more significant contributor to production in the Culpepper Martin, and that's reflected in the parameters that go into the simulation. It's also a somewhat lower-pressure area, and that's also reflected in the simulation inputs.

The next page in the exhibit shows what that simulation grid looks like. It was constructed with the same general ideas in mind as the 27-5 grid.

The history match follows, and again the solid line is the actual, the diamonds are the model, and where the solid line ends represents the projection of the model for the next 30 years.

The next page is a similar exhibit. One of the most marked differences here is that you'll see that the acceleration component is roughly 50 percent in Culpepper Martin. So it's quite a bit higher in Culpepper Martin. Where we've got a one-third/two-thirds split in 27-and-5, it's roughly 50-50 in Culpepper Martin, so there will be more acceleration.

One point to note on both of these graphs is, if you look at the blue section of the curve, which would tell you where you were starting to see significant quantities of acceleration, and move out about ten years and come up to the blue section, you'll see that it's a relatively insignificant amount of acceleration at that point. A lot of the acceleration is happening after. At a ten-year period on this graph, it's probably one-fifth/four-fifths acceleration and unique reserves.

Q. Does the Culpepper Martin area as modeled by simulation still justify the economic incentives to explore increasing the density?

A. The following page shows the individual well projections similar to 27-and-5, and we input some economic parameters into that to answer that very question.

And you can that see some of the significant differences here is Culpepper Martin being shallower than 27-and-5, these well costs are a little bit cheaper. Same operating costs, same pricing assumptions. And we do see a rate of return that, while not as favorable as the 27-and-5 rate of return, still looks worthy of pursuing, especially since there's some uncertainty in the model, and we can collect data to make us more certain about what's going to happen.

Q. It certainly warrants investigation as a pilot project at this point?

A. That's a fair statement.

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

We move the introduction of his Exhibit Number 9 in each of the books.

EXAMINER CATANACH: Exhibit Number 9 in each of the books will be admitted as evidence.

Questions, Mr. Chavez?

EXAMINATION

BY MR. CHAVEZ:

Q. Mr. McCracken, looking at your 27-5 history match and base projection, when you get as close a match as that appears to be -- I'm sorry --

A. That's fine.

Q. When your match is as close as that to actual production, do you think you're pretty good with your data at that point, or how far off are you when you have -- it matches that --

A. I think pretty good is a very fair characterization. You can match production in a number of different ways. There are different scenarios of back pressures and skins that we could have used to get this same match; but when you do, the pressures in the individual blocks change.

And when we drill increased density wells and get those actual pressures and determine which of those sets of back pressures and skins was the set that matches up best with the pressure, then I think we move from pretty good to right on.

Q. When you talk about getting more certainty, what degree or certainty, or how big a change would you anticipate with a higher degree of certainty and the recovery factors and all that you've already projected with your data you have for the different models --

A. Without that pressure, I think trying to answer that question would be speculation on my part.

Q. Have you used this model before in anticipation, say, for -- How to put it? The way the model is used now, is there a problem with using it, say, with the infill wells on 160 acres?

A. To predict what the recovery for the 160-acre wells that to date have not been drilled would be?

Q. That's right.

A. I think that could be done, yes.

Q. With a good degree of confidence?

A. Similar degree of confidence to the 80 acres at this point. Again, the pressure data would make me more confident.

Q. You heard me ask earlier about questions concerning statistical certainties that improve with more data. Do you recall those questions?

A. Yes, I do.

Q. Do you have a response to those?

A. I think the best response that I can give you is that this is a deterministic model, it really isn't a probabilistic model. So deterministic factors are going to tell us how close this model is, and it's not really a probabilistic analysis.

Q. So your model is then -- When you calibrate your model with more data, is it usable just in a smaller area, or how would you use that model to expand outside of the project or pilot area where the wells are drilled?

A. The description of the reservoir becomes reasonably unique when you've constrained it with both production and pressure data, so your confidence in moving away from the model would be higher if you were constrained by both of those parameters.

However, if you move too far away you would have to gather similar data again and go through another process where you made a prediction, saw how close it was and then compared both the production and the pressure data to your model, to increase your confidence in that new area.

Q. This is kind of an odd question, but when will you know if you have enough data or enough pressures to say, We've got enough, we can go with this? Do you have a set point in your plans for that?

A. Within this particular area, or within these two particular areas, we feel that when we have this pressure data and we've had a first delivery from these wells and they are producing into the line, that our confidence is as high as it's ever likely to be on where we should go from there.

Q. Well, I understand that, but is there some point when you could say, I've got four wells here and I've got these pressures; any more pressures really won't significantly impact the model such that we need them?

A. Oh, I see where you're going. Without knowing what those four pressures are, I would hesitate to make a conclusion on that at this point. If you had a couple that matched your model pretty well and then a couple that threw you a curve, I think you would probably feel very strongly about getting the rest of the data. If you had four that all matched up with what you had predicted or you could easily change your model to the point where they did match, then I think the answer to that question would be yes. But without that actual data in hand, I think it's dangerous to try to draw a conclusion at this point.

MR. CHAVEZ: I think that's all I have.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. McCracken, on your recovery profile graphs, are you -- with the total with infill drilling line that you've got, is that assuming four wells per section on that?

A. No, that's assuming the density of wells that's you know, applied for in the Application.

Q. Okay, just the eight wells?

A. Yes, eight for 27-5 and six for Culpepper.

Q. So the really uncertain factor that you put into these models is the initial pressure; is that correct? Or do you consider that to be a --

A. The initial pressure, I think, is probably fairly certain. It's a match on what the pressure is, let's say, April the 1st, 2000, or let's say at the point in time where an infill well was drilled that we feel like we don't have a good handle on it.

Initial pressures, we think, are probably within 50 p.s.i. either way.

Q. So you feel pretty good about all the data you've put into this simulation?

A. Yes, I do.

Q. Did you history-match anything but cumulative production? Did you history-match current production at all? Or is that not typically done?

A. I'm not sure I understand the term "current production".

Q. Well, current producing rates for the units or for the area, that's not typically matched.

A. Oh, the -- Yes, we did, we don't have a presentation of it here in the exhibits. The match on the rates -- Actually, we matched the rates through time, and the match was good.

Q. It was?

A. Yes. There are individual variations during periods of curtailment where production tends to be erratic.

EXAMINER CATANACH: I don't have any more questions of this witness.

Mr. Chavez?

MR. CHAVEZ: Could I just ask a question?

FURTHER EXAMINATION

BY MR. CHAVEZ:

Q. Are you familiar with Conoco's pilot project?

A. To a certain extent, yes.

Q. Are pressures available to you from their pilot project that would help you to calibrate your model?

A. There are pressures available. I think the reason why it would be difficult to calibrate my model with them is the geologic differences.

Q. Can't that be accounted for by changing those parameters in the model?

A. What we would have to do in my mind is build a geologic model of the Conoco project.

Q. Okay. Have you considered taking pressures from other Burlington Dakota completions to use to calibrate your model?

A. In fact, the one well that I referred to earlier that is outside the grid in an attempt to see if my model looked reasonable from a pressure standpoint with respect to that well -- the well was the San Juan 27-5 Unit Number 109-E, which is approximately a mile to a mile and a half northeast of my gridded area -- when it was initially completed there was a bottomhole pressure taken, and that pressure was, I believe, 2733 pounds.

And I went into all of the blocks in my simulator where an infill well was drilled in that 1985-1986 time frame, where that well was drilled, and averaged their block pressures at that time, and that average came out to be 2770 pounds.

So that match is good. I hesitate to hang too much on that, though, because that well is outside the grid, and the range of those pressures that averaged 2770 was about 2550 to 2950.

Q. Could you use bottomhole pressures from infill wells in tracts that haven't been infilled in this 27-5 unit to calibrate your model?

A. For instance, 160 wells that are --

Q. Yes.

A. -- currently programmed or that are going to be drilled?

Q. Yes.

A. Probably so.

MR. CHAVEZ: Thank you.

EXAMINER CATANACH: This witness may be excused.

Mr. Kellahin?

MR. KELLAHIN: That completes our presentation, Mr. Examiner.

EXAMINER CATANACH: Mr. Kellahin, with regards to the unorthodox locations, I didn't hear all that testimony about a justification for each of those separate. Was it just a mixture of factors for those locations?

MR. KELLAHIN: Well, it's more specific than that, Mr. Examiner. You've provided Mr. Babcock an opportunity to give you a geologic narrative as to the locations. We can provide a narrative to explain the topographic maps that are already in the exhibit book to specifically identify each location, if that helps you.

EXAMINER CATANACH: So the unorthodox locations, some are topographic and some are geologic; is that my understanding?

MR. KELLAHIN: Well, it's a combination of both. Mr. Babcock's first choice on a geologic location was not necessarily achievable and had to be moved further. In most instances, his geologic choice put the well at an unorthodox location inherently, because they were in undrained portions of the pool, because that's what's left for you once you follow the existing pattern.

Where they would fine-tune, had a surface component to it, and if -- It may help you, and I'm happy to draft the order for you if you would like, but we will include documentation to give it a well-specific explanation as to how you combine the two to get the location.

EXAMINER CATANACH: I would like a well-specific explanation on these locations --

MR. KELLAHIN: All right, sir.

EXAMINER CATANACH: -- if you could provide that to me.

MR. KELLAHIN: I'd be happy to do that.

EXAMINER CATANACH: I am also a little concerned, especially on the Culpepper Martin Unit, about non-notice to royalty interest owners. I'm not so concerned within the 27-5 unit, it does concern me in the Culpepper Martin

Unit.

MR. KELLAHIN: Well, I understand that, Mr. Examiner. The Division rules don't require it, we therefore didn't do it. Remember when we re-wrote the rules last year, the reason the overrides and royalties were left off notifications in cases like this is because it is the inherent responsibility contractually, by lease obligation, for the working interest owner and the lessee to take care of those individuals. And so that's what our testimony has been, and we'll do it in that fashion.

If you decide that you want us to go back and renotify, then we'll do what you tell us to do.

EXAMINER CATANACH: I want you to notify the interest owners, the royalty interest owners and overrides in the Culpepper Martin Unit.

MR. KELLAHIN: All right, sir.

EXAMINER CATANACH: I think we can dispense with that in the other San Juan 27-5 Unit.

MR. KELLAHIN: We'll be happy to do that, sir.

EXAMINER CATANACH: It would just make me feel more comfortable about it.

MR. KELLAHIN: Then we'll do it.

EXAMINER CATANACH: Okay. Is there anything further in this case?

MR. KELLAHIN: There's representatives from the

Bureau of Land Management here, and I don't know if they want to speak or not.

MR. TOWNSEND: Yeah, we want to make a statement --

EXAMINER CATANACH: Okay.

MR. TOWNSEND: -- if I don't lose my voice first.

EXAMINER CATANACH: Mr. Townsend?

MR. TOWNSEND: Yes, I'd like to make a statement that represents the position of the Bureau of Land Management concerning the technical aspects of Burlington Resources' Applications here today.

NMOCD Case Numbers 12,508 and 12,509 are to increase the Dakota formation well density to a maximum of four wells per gas proration unit, unorthodox, nonorthodox locations, in a portion of the 27-5 Unit and the Culpepper Martin project area.

Based upon the technical data presented by Burlington to the BLM on September 28th of this year, a review of the proposed application that we got and received from them, and the testimony we've heard here today, we are in support of these pilot projects. These projects will be critical in gathering additional reservoir engineering and geological data for the specific purpose of determining the proper well density in the Dakota formation.

However, the BLM has concerns regarding the potential drainage situation that we've heard today and that we've previously discussed. In the Culpepper Martin pilot project area the drainage situation exists because of the different mineral ownerships. These concerns were addressed in a letter to Burlington dated October 13th of 2000.

Just to take a minute and to digress from the pilot projects, if the pilot projects are successful and they are approved by the NMOCD, the BLM supports the drilling windows and the spacing rules for the Mesaverde and the Dakota to be similar or the same. We support this because of the commingling of the Mesaverde reservoir and the Dakota reservoir and minimized surface disturbances.

Also, if the pilot projects are successful, at this juncture the BLM is also in favor of Basinwide rules as similar to the Mesaverde. This would benefit all operators so that they could determine their own economics in whether to deepen the well to try to recover additional Dakota reserves.

In summary, the BLM is in support of these pilot projects as proposed by Burlington. The BLM contends that any drainage situations that may arise as a result of these pilot projects can be mitigated through existing processes and procedures. These pilot projects will provide valuable information to determine optimum well density and will maximize recoverable efficiency towards other formations.

The BLM is also in support of the other unorthodox locations, which potentially maximize the potential recoverable reserves and minimizes the additional surface disturbances.

That's my statements concerning the technical portions. Mr. Ruben Sanchez was wanting to address the surface portion.

EXAMINER CATANACH: Thank you, Mr. Townsend.

Mr. Sanchez?

MR. SANCHEZ: Some of the things that I will say are parallel to what Mr. Townsend just addressed, because they do impact a lot of the surface resources, which is predominantly my concern for myself and my staff with the environmental protection section.

We do promote and will continue to promote environmentally responsible permitting of the pilot projects as these projects are presented and carried forward, based on approval by the NMOCD.

We also encourage industry to continue looking and considering directional drilling or any other innovative ways to produce the subsurface resources, to minimize the impacts to other resources that are shared by the public in general.

The staff with the environmental protection will continue to ensure conformance with NEPA for all permitted actions that come out of our section. Professional judgment will also continue to be applied for all on-sites, whether they be pilot or just a spacing that have already been previously approved, particularly right now as we go through the EIS revamping of the Resource Management Plan.

We'd also like to encourage NMOCD to consider the flexibility of the nonstandard locations, as this will help reduce surface resource impacts. Surface resources must be taken into account if there is to be something left for future generations to enjoy within the Four Corners area.

Any future projects that are presented that will include or increase well density severely impacts all of our programs -- those being wildlife, recreation, grazing -- that are enjoyed by the public in general. And that is why, I guess, from my standpoint, from the surface impact side, we'll be strongly supporting looking for innovative ways to develop that.

On behalf of the Bureau, we are not here to express opposition to your development efforts. That is not in any way -- should not be taken, what I just said. We're all for it. It's just, there's other resources which we hope to consider.

Thank you.

EXAMINER CATANACH: Thank you, Mr. Sanchez.

Anything further?

MR. HAWKINS: Yes, Bill Hawkins with BP Amoco. We'd like to make a statement in support of the Application by Burlington.

BP Amoco supports the approval of the 80-acre infill pilot project in both of these locations in the Basin-Dakota Pool. We support the testing of 80-acre infill pilots in several parts of the pool for proving the concept for the rest of the pool.

We don't have a plan to conduct an infill pilot on any of our acreage, and I think you've heard today difficulty in trying to identify pilot areas where correlative rights can be protected.

We believe if these pilots are successful, that ultimately 80-acre infill development for the entire Basin-Dakota Pool should be approved. The Dakota formation is generally lower in permeability than the Mesaverde, where the NMOCD has already approved 80-acre infill. The most economic way to implement 80-acre development in the Dakota is to tag along with the 80-acre infill development in the Mesaverde, using common wellbore, well-location pads and roads.

The 80-acre infill development in the Mesaverde is already undergoing, and the longer we wait to approve 80-acre infill of the Dakota, the more 80-acre Dakota locations may be left undeveloped, which would create waste.

We ask that the NMOCD approve these pilot projects with a short six- to twelve-month time frame for implementation. And we ask the NMOCD to recall both Burlington and Conoco for hearing to provide the data and results obtained from the pilot projects and to consider 80-acre increased density for the development of the entire pool.

EXAMINER CATANACH: Are there any other statements in this case?

Mr. Kellahin, if you would be so kind, I would like draft orders in both these cases.

And with that, Case 12,508 will be taken under advisement, and Case 12,509 will be continued to the November 16th hearing, which I assume will give you proper time for notice in this case?

MR. KELLAHIN: Yes, sir. We'll discuss after the hearing tabulating the data to send the notice out. I think we can do it very quickly. And before we decide whether to close or continue the case, let me check and see when I can get my notices satisfied. Is that how you'd like to do it?

EXAMINER CATANACH: Well, I think we need to continue it to November 16th at the earliest.

MR. KELLAHIN: At the very earliest.

EXAMINER CATANACH: At which point, we can always continue it further from that --

MR. KELLAHIN: Let's do that.

EXAMINER CATANACH: -- if we need to.

MR. KELLAHIN: Yes, sir.

EXAMINER CATANACH: Okay. All right, thank you.

(Thereupon, these proceedings were concluded at 12:44 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 October 24th, 2000.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 2002