STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION COMMISSION

COMMISSION HEARING

IN THE MATTER OF: Case 9765

Application of Meridian Oil, Inc., for a highy-deviated directional drilling pilot project, unorthodox gas well location and an exception to Rule 2(b) of the Special Rules Governing the Blanco-Mesaverde Pool, San Juan County, New Mexico.

TRANSCRIPT OF PROCEEDINGS

BEFORE: WILLIAM J. LeMAY, CHAIRMAN
WILLIAM WEISS, COMMISSIONER
WILLIAM HUMPHRIES, COMMISSIONER

STATE LAND OFFICE BUILDING

SANTA FE, NEW MEXICO

January 18, 1990

ORIGINAL

A P P E A R A N C E S

FOR THE OIL CONSERVATION COMMISSION:

ROBERT G. STOVALL, ESQ.
State Land Office Building
Santa Fe, New Mexico 87501

I N D E X

MR. LeMAY: Call Case No. 9765.

MR. STOVALL: Application of Meridan Oil, Inc., for a highly-deviated directional drilling pilot project, unorthodox gas well location and an exception to Rule 2(b) of the Special Rules Governing the Blanco-Mesaverde Pool, San Juan County, New Mexico.

Applicant requests this case be continued to February 15, 1990.

MR. LeMAY: Is there objection to that continuance? If not, we shall continue that case to the February 15 docket.

CERTIFICATE OF REPORTER

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

I, Debbie Vestal, Certified Shorthand Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Commission of the Oil Conservation Division was reported by me; that I caused my notes to be transcribed under my personal supervision; and that the foregoing is a true and accurate record of the proceedings.

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

WITNESS MY HAND AND SEAL February 20, 1990.

Debbie Vestal

Debbie Vestal
CSR No. 400

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NEW MEXICO OIL CONSERVATION COMMISSION

COMMISSION HEARING

SANTA FE, NEW MEXICO

Hearing Date FEBURARY 15, 1990 Time: 9:00 A.M.

NAME	REPRESENTING	LOCATION
W T Kellahin	Kellahin Kellahin Aubrey	Santa Fe
Kent Beers	Meridian Oil Inc.	Farmington
JIM CRADDICK	" " "	"
G.T. DUNN	" " "	"
Bob Hopkins	" " "	"
Greg JENNINGS	" " "	"
KENT LUND	AMOCO PROD CO.	DENVER
LARRY EMMONS	" " "	"
[illegible]	Byram	Santa Fe
John [illegible] III	Burlington Resources	Santa Fe
Don [illegible]	Meridian Oil Inc	Houston, Tex
[illegible]	" "	" "

STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION COMMISSION

CASES 9764 and 9765

COMMISSION HEARING

IN THE MATTER OF:

Application of Meridian Oil, Inc., for a Highly-Deviated Directional Drilling Pilot Project, Unorthodox Gas Well Location and an Exception to Rule 2(b) of the Special Rules Governing the Blanco-Mesaverde Pool, San Juan County, New Mexico

TRANSCRIPT OF PROCEEDINGS

BEFORE: WILLIAM LEMAY, CHAIRMAN
WILLIAM WEISS, COMMISSIONER

STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO
February 15, 1990

A P P E A R A N C E S

FOR THE DIVISION:

ROBERT G. STOVALL
Attorney at Law
Legal Counsel to the Divison
State Land Office Building
Santa Fe, New Mexico

FOR MERIDIAN OIL, INC.:

W. THOMAS KELLAHIN, ESQ.
Kellahin, Kellahin & Aubrey
Post Office Box 2265
Santa Fe, New Mexico 87504

FOR AMOCO PRODUCTION COMPANY:

KENT J. LUND, ESQ.
1670 Broadway
Post Office Box 800
Denver, Colorado 80201

I N D E X

E X H I B I T S

CHAIRMAN LEMAY: Now I'll call Cases 9764 and 9765.

MR. STOVALL: These are the applications of Meridian Oil, Inc., for a highly-deviated directional drilling projects, unorthodox gas well locations and exceptions to Rule 2(b) of special rules governing the Blanco-Mesaverde Pool, San Juan County, New Mexico.

CHAIRMAN LEMAY: Do I hear a motion on these cases? Mr. Kellahin?

MR. KELLAHIN: Mr. Chairman, for the record my name is Tom Kellahin. I'm an attorney with the Santa Fe law firm of Kellahin, Kellahin and Aubrey. I'm appearing today on behalf of Meridian Oil, Inc.

I've discussed this matter with Mr. Lund, who is attorney for Amoco appearing today on their behalf, and he has no objection to my motion at this time to consolidate both those cases for hearing purposes this morning, and we would so move.

CHAIRMAN LEMAY: We move the cases be consolidated. Are there any objections to this? If not, the cases will be consolidated.

I'll now call for additional appearances in Cases 9764 and 9765.

MR. LUND: Good morning, Mr. Chairman. My name is Kent Lund appearing on behalf of Amoco

Production Company, and I'm appearing in association of Charles Sanchez of Belen, New Mexico.

CHAIRMAN LEMAY: Thank you, Mr. Lund. You'll have witnesses for us today, or not?

MR. LUND: Potentially. As the Chairman may be aware, the only thing we're really concerned about is the deliverability allowable calculations for the proposed proration units with these deviated wellbores. We don't object to the fact that Meridian wants to drill them. In fact, we're excited about that. We just have some concerns for the correlative rights, and that's our issue today.

CHAIRMAN LEMAY: Thank you, Mr. Lund. Additional appearances in the case?

MR. KELLAHIN: Mr. Chairman, I would like to introduce at this time the General Counsel of Meridian Oil, Inc., Mr. Gavin Smith. Mr. Smith is a member of the Texas bar and has come today to be present for the hearing today. Mr. Smith, would you please stand.

CHAIRMAN LEMAY: Mr. Smith, we're glad to have you hear in Santa Fe.

At this time we will swear in all the witnesses who will be giving testimony. Please rise and raise your right hands.

(Thereupon, all witnesses were sworn.)

CHAIRMAN LEMAY: Mr. Kellahin, you may proceed.

MR. KELLAHIN: Mr. Chairman, we want to attempt to do something a little differently before the Commission today than is our typical presentation form. In the past, in disputed cases, it is often the style to take each of the experts and lead them through a presentation of their technical case. We believe that is not the kind of case we want to present to you today.

As Mr. Lund indicated, we are pleased and delighted with the Examiner Order in all issues except one. We are pleased that the Examiner has found that this unique opportunity to attempt to recover additional gas reserves out of the Mesaverde Formation in the San Juan Basin is one that he endorses.

The topic of discussion today is going to be a project, a pilot project, if you will, for what we characterize as a highly-deviated well, a high-angle well, if you please. We are selecting to try to determine whether or not that technology will give us an opportunity to further develop gas reserves out of the Mesaverde Formation.

I think we all appreciate and recognize the wonderful success we have all enjoyed from the in-fill program in the Mesaverde. Our background information we want to present to you today explains some of the bases upon which the Examiner entered the order endorsing the fact that we have the opportunity to recover yet again reserves that are not yet being produced. So we are pleased with a number of his findings.

The single exception that we have with the order as entered is the establishment of a special project allowable. And that will be the focus of our concentration this morning. I want to present to you three technical people to give you a background on the project, but the focus, then, will be for them to explain to you the special project allowable.

As you know, the Mesaverde is a prorated gas pool. We have sought to come up with a special project allowable within the context and the framework of the proration system for that reservoir. In doing so, the technical people will talk to you about how to make that calculation.

In order to have the economic incentive to go forward with this project, we are requesting a modification of the Examiner Order. We are requesting that in order to calculate the spacing unit allowable, that you grant us the right to take the deliverability of the high-angle well and multiply that deliverability by two, and subsequently integrate that into the allowable calculation.

Mr. George Dunn is a reservoir engineer who will make the first presentation and show you his justification for his allowable request. He'll talk to you about his economics and we'll get into all the ramifications of that particular issue.

I'll also present to you Mr. Greg Jennings, Meridian's geologist, who will give you a presentation of the geologic basis upon which we have predicated the pilot project.

My last technical witness is Mr. Louis Jones. He is known to the Commission, he has testified before you on a number of occasions on prorationing, and he is prepared to discuss with you the mechanics of how to handle the formula.

One of the things that we did not give Examiner Catanach the opportunity to hear is the question of the maximum possible producing rate for the high-angle well, and that was Amoco's concern. They were concerned that our request did not have a cap or a ceiling on the producing rate for the spacing unit, and it was possible, then, under our presentation, that the offsetting spacing units might have to compete against a high-angle well in a way that they would not be exposed to competition if this had been a vertical well.

We want to discuss that issue and hopefully address some of their concerns about establishing what we think is an appropriate ceiling or cap on the total allowable for our spacing unit that will hopefully satisfy your concerns and Amoco's concerns about any opportunity for an unfair advantage.

Amoco was at the earlier hearing. I think everybody agrees that this is technology that ought to be explored in New Mexico. I'm personally delighted that Meridian has chosen New Mexico to do this activity, but I'm also hear to tell you that unless we can have an incentive, in terms of this project allowable as we propose, then unfortunately we're not going to be able to go ahead with the project.

I have technical witnesses that will explain to you that position, but that is part of the presentation today. And therefore I would request, Mr. Chairman, that we incorporate for the record, so that we do have a complete record, the Examiner transcript so that I don't have to go through all the building steps to build the case, and we'll focus directly in, then, on this question of this project allowable.

CHAIRMAN LEMAY: Are there any objections to incorporation of the transcript?

MR. LUND: No objection.

CHAIRMAN LEMAY: Thank you. The transcript of the Examiner hearing will be a part of this record.

MR. KELLAHIN: Mr. Chairman, so we can focus on that portion of the Examiner Order that gives us our concern, I would like to circulate to you a copy of the existing order entered in this case, along with a proposed language change that we can discuss this morning that we believe solves our concerns.

In order to approve our request before the Commission, the language we have proposed, which is referenced number 8, refers to page 6 of the existing order and looks to the ordering paragraphs. It's ordering paragraph number 8 that established under the Examiner Order the level of the allowable for the spacing unit.

What Mr. Catanach approved was the option to use the deliverability of the high-angle well or, in the alternative, the sum of the deliverabilities of the two vertical wells in the spacing unit. In each of these cases we have an original Mesaverde well and an in-fill well. The language change here is simply to provide authority to take twice the deliverability of the high-angle well in the calculation. The further discussion in that subparagraph (1) is our efforts to put in place a cap or a ceiling.

With your permission, Mr. Chairman, I would like to call our first witness, Mr. George Dunn.

CHAIRMAN LEMAY: Please proceed.

GEORGE T. DUNN

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

MR. KELLAHIN: Mr. Chairman, while Mr. Dunn was taking his place in the witness chair, I have handed out to Mr. Lund and to other participants and to the Commission, Meridian's exhibit book. We have simply marked the exhibit book as Meridian Exhibit 1, and then each of the pages and displays in the book are numbered one through whatever the last number is.

We have taken some of those displays and made larger copies to aid in understanding the testimony of the technical people, but if you have one of the covered booklets, this will contain all of the exhibits we're presenting today.

EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Dunn, for the record, would you please state your name and occupation.

A. My name is George Dunn. I'm a senior staff reservoir engineer for Meridian Oil, Incorporated, in Farmington, New Mexico.

Q. Would you summarize for the Commission what has been your personal involvement with this project?

A. I was on an initial team which consisted of an integration of several departments within Meridian Oil, and I was the reservoir portion of that team, to determine some methods to enhance ultimate recovery in the Mesaverde Formation in the San Juan Basin.

Q. How long have you worked as part of Meridian's technical team on this particular project?

A. Approximately 9 to 10 months now.

Q. You have a bachelor's degree in petroleum engineering, sir?

A. Yes, sir. I have a bachelor's degree from the Colorado School of Mines.

Q. What year?

A. 1979.

Q. You previously qualified as an expert reservoir engineer before this Division?

A. Yes, sir.

MR. KELLAHIN: Mr. Chairman, we tender Mr. Dunn as an expert engineer.

CHAIRMAN LEMAY: His qualifications are accepted.

Q. Mr. Dunn, would you summarize for the Commission--and perhaps let's go to the locator map. Show us the two spacing units, if you will, that are the two pilot projects that we're discussing this morning.

A. This is a locator map that has the outline of the Blanco-Mesaverde pool in orange. Farmington is approximately in this area, Bloomfield. Within that locator map we've highlighted 9 section areas for the Howell "E" 2, proposed Howell "E" 2R well, and also around the proposed Riddle 1R in the center, basically, of the Blanco-Mesaverde pool.

As you can see, we've blown up for both the Howell, on the right, and the Riddle, those nine-section plats. In addition, I might point out now, that we'll be talking briefly about a couple of other proration units that are within this locator map, one being the Howell "D" 3B proration area and it's in this location basically in between the two areas we're talking about, and then we're going to move up into the northwest section and talk about the Scott 2R.

The Howell "E" 2R is located in Township 30 North, Range 8 West, and it's in Section 14. It would be in the east half. Colored in yellow is the acreage that Meridian operates and outside-operated acreage is in white. Basically these three sections to the east of the Howell "E" 2 proration unit is part of the Northeast Blanco Unit, and all of the other sections are Amoco-operated.

Q. Summarize for us, Mr. Dunn, what was the purpose of the study?

A. The purpose of this study was two-fold. Number one, to go in and look for old open-hole Mesaverde wells that produce inefficiently due to the open-hole collapsing and/or not even being drilled all the way through the Mesaverde Formation. On top of that, we were in search of additional ways to increase ultimate recovery because we're nearing the end of the in-fill program, and after the in-fill program is done, we're in search of a way to increase recovery beyond those two, and there are ways to do that.

Q. Why did you select Mesaverde as the formation or the pool to study?

A. It's the largest reserve base in the San

Juan Basin. It's also one of the largest of Meridian Oil's, and therefore it offers a high potential for an increased recovery and impact to both Meridian Oil and the State and the San Juan Basin.

Q. Why have you selected the use of highly-deviated wellbore technology or high-angle wells to study in this particular pool?

A. The concept of the highly-deviated well is to determine if we can intersect additional pods of sand, reservoir containing gas that are not in communication with vertical well due to permeability barriers or whatever. And these have been indicated before in several cases, one in Van Everdine's testimony for the in-fill program. He discussed some of the lenticular nature of the sand.

In addition, we'll show some redrill criteria where we've redrilled wells and gained additional recovery in the reservoir.

Q. Why use highly-deviated wellbore technology for exploring the additional reserves in the Mesaverde versus a third vertical well in the spacing unit?

A. The highly-deviated well will afford us increased chances of intersecting these pods basically by increasing the cross-sectional area that we're able to contact within the proration unit.

Q. Describe for us the criteria, Mr. Dunn, that the project technical people selected in order to identify spacing units to use for the pilot project.

A. Again, the initial emphasis was to locate areas where we had old open-hole completions. We felt they were not competitive with offset leases. In addition, that there was inefficient production going on. That was the initial emphasis.

Then, as we narrowed down to these location and wells, with the introduction of the concept of the highly-deviated well we looked for areas of 100-percent working interests so that we could initiate this project quickly, gain data so that if it was successful when we went to outside owners, partners and other areas, we would have data to show, then, that it's worth the extensive capital increase to actually drill these wells.

Also, these two just happened to have surface locations. As you can see, they're dotted in orange or, excuse me, they're just offset to the orange of the original well, which is tucked into the northern portion of the proration unit. Our idea is to be able to drill to the south the full length of this proration unit in the drilling window and get away from the old wellbore and what it saw within the

Mesaverde.

Q. Why have you and the other technical people selected the spacing unit for the Riddle well and the Howell well for the pilot project?

A. These are just two of several wells that we could have selected. We propose two wells to be able to fully test the technique. We feel like one well either did mechanical failures or productivity failures may not fully explain whether or not this is a successful technique to use; so, we selected two that are multiple locations that we could select. The primary emphasis of this was this is the meat of the Mesaverde in this area. It reduces potential productivity problems that we might encounter on the fringe, so we went to the center of the proration unit.

In addition, there has been several successes of vertical redrills and therefore in terms of increasing reserves, so we have a statistical base to compare these deviated wells against the vertical wells that exist out there that have already been redrilled.

Q. I think page 2 of your exhibit book is a reproduction of each of the two spacing units?

A. That's correct.

Q. After that display is page 3, and that looks at the current deliverabilities of the wells in the Howell area?

A. That's correct.

Q. Let's go to that, Mr. Dunn.

A. This is the same nine-section plat here for the Howell "E" 2 area.

Q. When we look at the spacing unit for the Howell and its two vertical wells that exist on that spacing unit and look at the current deliverabilities of those wells around that spacing unit, what do you find?

A. You find that the proration unit of the Howell "E" 2 and Howell "E" 2A has a significantly lower deliverability than those offset to it. And this is primarily due to the Howell "E" 2 which is an old open-hole completion that I've already discussed. Therefore, we see that we're in a less competitive situation because of this old wellbore.

Q. When we look at the spacing unit surrounding the Howell spacing unit, do each of those corresponding spacing units have an original and an in-fill well on them?

A. That is correct.

Q. In terms of correlative rights, Mr. Dunn, do you see any opportunity to have any of the offsetting owners' correlative rights impaired if the pilot project is approved, as we propose it be amended, by this Commission?

A. No, I do not.

Q. And why not?

A. The proposal is to set a cap for the two times the "D" of the highest proration unit that is currently drilled with two vertical wells. That would be--in other words, what we're adjusting this cap to is the risk factor that is there, if we were to drill two vertical wells. It would protect them the same as us coming in and drilling two new vertical wells, the highest risk that's out in the basin currently.

Q. In addition, those spacing units are already competitive insofar as they do have or had an original and an in-fill well?

A. That is correct.

Q. And currently their deliverabilities exceed yours?

A. At least by double.

Q. Let's go to page 4 of the exhibit book. Before we discuss your conclusions, Mr. Dunn, let's look at what you have presented. What are you showing?

A. This is a linear material balance, a P/Z plot, for the Scott 2 and Scott 2R wells. This was a well that I pointed to in the northeast section of this locator map earlier. It is a plot of bottom-hole pressure/Z, versus cumulative production, for an original well and then for a redrill well.

Q. What's the conclusion?

A. The conclusion is that the Scott #2 had potential original gas in place of about five and a half Bcf. By redrilling this well, you can see that we've changed the slope of this line and increased reserves somewhere upwards of three-fold.

Q. What does that tell you about the Mesaverde?

A. It tells us that--and I should mention, also, that well was within 2- to 300 feet of the old wellbore--that you're capable of picking up areas that are not being produced by an original wellbore by moving within the Mesaverde, and that's because of the lenticular nature of the sand, and also because of the permeability and porosity enhancements that can occur throughout the basin.

Q. You have found that occurrence in the Scott spacing units. Do you find that to occur in other spacing units in the Mesaverde?

A. In all of the redrills we've done so far, this is a typical example.

Q. Let's go to the P/Z curve on the Howell wells, Mr. Dunn. Having plotted the pressure versus cum. for the Howell wells, what do you conclude?

A. This is basically the identical conclusion as from the Scott 2 and Scott 2R except it does show one additional item. The initial pressure Pi for the Howell "D" 3B was approximately 70 psi higher than the Howell "D" 3 was. Therefore, it's additional proof of picking up additional pay that was not being produced by the original Howell "D" #3 well. Again, you can see the increase in reserves by the change in slope of the line by plotting these two together.

Q. That confirms, then, the necessity of the in-fill program for 320 gas spacing in the Mesaverde pool?

A. It confirms the necessity of the in-fill program and also confirms the necessity to search and look for areas where we can pick up additional recovery within the Mesaverde.

Q. Let's go on now to the discussion of the Howell in terms of its vertical and horizontal locations. We can leave these up, and let's look at the Howell map. All right. We're looking at larger

copies of what is page 6 to your exhibit book?
A. Correct.
Q. So that we have an understanding of the basis for the project, lead us through a discussion of how the well is going to be drilled and what you hope to accomplish with the drilling of the highly-deviated well.
A. Basically, in terms of just the drilling side of it, we'll drill vertically to a kick-off point and kick off and build a ramp angle all with the mud. Then we'll set approximately 100 feet above the Mesaverde Formation, we'll set an intermediate string of casing, and we'll drill out and be drilling the ramp with gas all the way through the Mesaverde.
To our knowledge, this has not been attempted in the State of New Mexico nor in the western half of the United States. So the interesting part, from a drilling standpoint, not only is the highly-deviated, but we're doing this with gas. From a reservoir standpoint, what we have is a plan view of the proposed wellbore, proposed wellbore, and a cross-sectional view of the proposed wellbore, and spotted on this is the original Howell "E" #2 well, the proposed Howell "E" 2R deviated well, and then the Howell "E" 2A in-fill well.

We've colored in on here three of the intervals within the Mesaverde. Those can even be broken down further, but basically we'll enter into the Cliff House Formation, drill through the Cliff House at our ramp angle of approximately 68 degrees, and this entry point will not infringe upon the 790-foot setback. In fact, the plan right now is approximately 1000 feet from the north line. We'll intercept the Menefee, drill through the Menefee, and then through the lower Point Lookout, and TD at a point no closer than 790 feet from the south line. This is shown basically on the plan view to the right.

At the same time we have colored in the formations and where approximately we will intercept them within this proration unit as we drill through.

Q. Your display also shows you the location of the two existing vertical wells in the spacing unit?

A. That's correct. On the plan view you can see it somewhat easier. The Howell "E" #2 will be just north of the surface location of the Howell "E" 2R but will be almost 900 feet away when we actually intercept the top of the Mesaverde and the Cliff House.

The Howell "E" 2A is tucked down in the

right-hand corner of this drilling window, and we'll be drilling due south towards the south line. We'll require this whole drilling window in terms of use for drilling, but if at any time we approach any of those setbacks, then we'll determine if we can get away, make a correction to not go across that, or stop the well.

Q. We've characterized this as a highly-deviated or high-angle well. Approximately what is the angle for the Riddle and the Howell well?

A. The Howell, as I've mentioned, is about 68 degrees; the Riddle will be about 73 degrees.

Q. How is this different from a horizontally drilled well?

A. A horizontally drilled well will come down, and when it builds its angle it will come to a 90-degree bend, and it would drill across, in terms of speaking on the Mesaverde, would drill through just the upper Cliff House, which is the top formation or you could pick any of the other formations. It would not be in contact with the full interval of the Mesaverde.

Therefore, you would only produce from a part of the Mesaverde. That's why the horizontal technique is not conducive in this situation. The other option would be to drill multiple laterals at an extremely high cost.

Q. Describe for us, Mr. Dunn, what you see or what your work group concluded to be the advantages of the highly-deviated well?

A. The major advantage of the highly-deviated well is, in the case of the Howell "E" 2R, you'll note that we drilled in the Mesaverde formation for almost 3150 feet. That's about a three-fold increase of contact area over the vertical wells which are, at maximum, about 1,073 feet, 1100 feet, approximately. So it affords us the advantage of contacting three-fold the formation across the proration unit, and increases our chances of intersecting these areas that aren't being drained with the vertical wells.

Q. You've identified on your display some disadvantages. Why have you selected those as disadvantages and what are they?

A. The main disadvantage is, since this is a brand-new technique, it includes a high risk of failure and/or a high risk of increased capital to be successful. And those would be the first two reasons, high mechanical risk and high cost. In fact, the initial investment is a high cost. The actual drilling cost is about three times that of a vertical well, and to complete and set full facilities we're about two, two and a half times the total cost.

The biggest disadvantage would be to spend the capital to test this technique and find out we cannot increase ultimate recovery over that that we have with redrilling of just a vertical well.

Q. In your opinion, will the additional surface of the formation contacted with the highly-deviated well give you a direct relationship to the deliverability of that well?

A. No, not just the contact area. The major thing that will control any productivity, whether it's a vertical or horizontal well, will be the permeability of the formation. And just by the increased contact area, we won't gain an advantage production-wise, productivity-wise.

Q. Let's go to the analysis that you have on page 7 of your exhibit book. You've been asked to examine the Examiner Order that was entered in this case. Have you done that, Mr. Dunn?

A. Yes, sir.

Q. Would you describe for us, in a simple way, what it is that is the problem with the Examiner Order?

A. Basically, by attempting to drill this highly-deviated well, we've lost part of the allowable calculation and we feel like this is not a good thing to do when we're taking additional risk to drill this well to try to increase ultimate recovery. From an economic standpoint, this is a plat that helps to support the increased rate that would be required from a highly-deviated well just to break even with a vertical well.

Q. Let's give them some background before you talk about your analysis. What kind of cost factors were you using for a vertical well?

A. The vertical well runs us about $400,000 typically, to drill, complete and have facilities to produce it down the line.

Q. What does it cost to drill the highly-deviated well?

A. The highly-deviated well estimated cost at this point is about $990,000, almost a million.

Q. That's for drilling, completion and other equipment?

A. Other facilities, right.

Q. When we look at the drilling portion of a vertical well and compare it to the drilling portion of the highly-deviated well, what magnitude of difference is there?

A. You're talking about a little bit over a three-fold increase just to drill the highly-deviated well over that of a vertical well.

Q. In order to understand the economics by which you then judge if the Examiner Order has given you an adequate level of economic incentive for the project, what did you do?

A. I performed a break-even analysis with some basic assumptions to determine at what level the highly-deviated well would have to produce to give us a break-even factor and then, in addition, looked at some cost-sensitivities later.

Q. Before you get to the conclusion, tell us how to read the display.

A. This is a plot of initial gas rate on the X axis against a net present value on the Y axis. What I've done is sensitized initial rates for the high-angle well, and that's the square dots and the lines going through those. Basically it shows a net present value and an initial rate. For the high-angle well, as we get higher rates, higher net present value.

In addition, what I've shown on here is the net present value we can obtain from doing a new vertical redrill, along with utilizing the in-fill well, which would be the standard practice in the proration units right now. That net present value is the dotted line coming across to intersect the highly-deviated well sensitivity. What it shows is just to break even, without including any additional risk, that we would have to have an initial rate of 2.7 times that of an average redrill well.

Q. Of the rate of an average redrill?

A. Correct, rate of an average vertical redrill.

Q. Did you do any other kinds of analysis in order to see what the incentive was required for the project in terms of an allowable?

A. We, in addition to that, looked at cost sensitivities because of the high risk to see at what risk we were as a company. As we started increasing cost, how much fold that increased the rate that we had to get from the highly-deviated well.

Q. It's not Meridian's practice, nor anyone else's practice in the industry, to your knowledge, to simply drill wells to break even, is it?

A. No, and that's true, too. What we're looking for is a situation to make more money than that of a--especially in this case, a vertical well that costs us half as much at the minimum, we would need to do more than break even to move ahead with this project.

Q. Your break-even analysis is predicated on a highly-deviated well costing how much?

A. $985,000.

Q. Have you studied to see what happens to your economics if you're required to spend some percentage in excess of that amount?

A. Yes, we've looked at increases in cost.

Q. Have you plotted that?

A. Yes, sir.

Q. Let's go to page 8. What have you done on display page 8 that is different than what we found on page 7?

A. Basically it's the same type of plot in terms of the X and Y axis. In addition we plotted two new sensitivity lines, one with the triangles and one with the circles, and those are net present values versus rate sensitivities for increased costs of 25 percent in the case of the triangles, and a 50-percent increase in cost for the circles.

Q. What does the analysis show you?

A. The analysis indicates that you can see the base case is still plotted on here, 2.7 times. If we go to a 25-percent increase, which is the lines with triangles, we end up with four to four and a half-fold increase in rate that we have to get to again break even. If we go to a 50-percent increase, it's going to be greater than a six-fold increase in rate that we have to get from a highly-deviated well to break even.

Q. Why don't you take your seat again. Do you, Mr. Dunn, have any reservations as a reservoir engineer having studied this particular project, that the opportunity as afforded you with the drilling of these pilot wells to recover reserves that might not otherwise be recovered?

A. Yes, I believe that we can do that.

Q. Can you conclude, therefore, that approval of this project will prevent waste?

A. Definitely, that if it is not moved forward with, that reserves can be left in the ground.

Q. Let's address now the other portion of the Commission's concern in any case, and that's correlative rights. Do you have an opinion as to whether or not the approval of this project, as we propose to set the allowable and in place a cap on that producing rate for the project, does that give you an unfair advantage over Amoco or any of the other operators?

A. No, it doesn't.

Q. Describe for us why not.

A. I believe it's a fair and equitable solution to the deliverability problem, and that is based on the fact that we are introducing a cap which is the same as exists currently in the San Juan Basin for vertical wells.

Q. Explain that to me, Mr. Dunn.

A. There exists proration units out there currently with two vertical wells that we can base this cap on, that we could also drill two new vertical wells in either the Howell "E" 2 proration unit or the Riddle, and potentially gain that same level of production.

Q. Let's put you in Amoco's position. Would you, as a reservoir engineer, have any objection if Amoco was to put in place a pilot project as you're proposing here and you're in the offset position?

A. No. I would gladly like to see them do that so I can see the results of the study, also.

Q. Describe for us, if you will, the mechanics of how you propose to put in place the special project allowable by the use of the deliverability. And let me have you begin at the beginning. Let's start with an original Mesaverde well, under the proration system, and tell me the mechanics of how that producing rate is established for that well.

A. When the initial well is drilled in a proration unit, the parent well, that well acts as the only well to be calculated into the deliverability calculation. It's run through a state deliverability test, and based on that test a state "D" is arrived at, which is a function of the productivity of the well and draw down of the well, and that state "D" is then entered into the allowable allocation-type formulas, but only that one well would be included at that point.

Q. Under the proration system in place for the Mesaverde, then part of the formula is based upon the deliverability or the capacity of the wells?

A. That is correct. Approximately 75 percent is deliverability and 25 percent is acreage.

Q. For those spacing units that have exercised the opportunity for an in-fill well in the spacing unit, how then is the allowable calculated?

A. As soon as you drill the in-fill, it is also taken into consideration in the same manner. The tests are run, the two deliverabilities, state "D's" that come from the two--now-existing two vertical wells, are added together to give you a deliverability for the total proration unit. Basically, it's equivalent to having 160-acre proration units, even though we're working on a 320 acre with in-fills.

Q. Does the Commission give you the opportunity to produce that allowable out of either well exclusively or in combination among the two wells?

A. That's correct.

Q. What happens in those situations where we have a third well in a 320-gas spacing unit for the Mesaverde?

A. The standard practice in the two examples that we showed are both that case, the Howell "D" 3B and the Scott 2R. There is three active wellbores in the proration unit, two in the north half and one in the south half. In that case, when you drill the third well, you can test all three wells. You have the option of utilizing either of the two wells that are in the same quarter section.

Q. Utilizing the deliverability of either of those two wells?

A. The deliverability of either one of those, but only one, and then the opposite quarter section that only has one well, then you would add it in. So you would use two out of the three wells, with one of those coming from the portion that has two wells in it.

Q. What options or alternatives did the Examiner Order provide to you in setting the allowable for the spacing unit?

A. With the highly-deviated well?

Q. Yes, sir.

A. With the highly-deviated well, the ruling was that we could use one times the "D" of the highly-deviated well, or add the two vertical wells together to get our total deliverability. So, basically, we lost at least one well out of the standard practice.

Q. Why do you need twice the deliverability of the deviated well in order to have an economic incentive for a special project allowable to let you go ahead with the project?

A. Twice the allowable reduces some of the risk that we're taking, and gives us an incentive to move forward and attempt to drill this project. In addition, this is a wellbore that crosses--covers, basically, the full 320 acres due to its highly-deviated nature, and therefore it's covering the full 320 acres and could act as two wellbores.

Q. Does doubling the "D" for the deviated well give you an unfair competitive advantage over the offsetting operators?

A. No, I do not feel it does, because again the productivity of the well is primarily a function of the permeability within the formation, reservoir pressure and some other things. In this case we're attempting to find higher permeability regions, additional reserves within our own proration unit, and it is not a function solely of the shape of the wellbore, and the two "D" would, again, assist us in reducing our risk up front.

Q. Why can't you go ahead with the pilot project, get your wells drilled and come back after the fact when we know what the producing rates or the capacities of these wells is going to be and then set an allowable for the spacing units?

A. At that point we would have judged the economics of the project up front on one assumption, and then the assumptions could change down the road and we would end up with potentially an uneconomic project that we've built on.

Q. Have you considered whether or not there is an unfair competitive advantage that your project will enjoy over the offsetting properties in terms of drainage?

A. The drainage concept from the

highly-deviated well would be very little different from a vertical well, and that is, a vertical well has a radial drainage that is currently of whatever radius.

When you drill the highly-deviated well, you still have similar drainage radius, but that drainage radius is moving down the length of the proration of the drilling window, so what you're ending up with is sort of a tilted cylinder coming down the proration unit. Your radius is not going to change unless you intercept enhanced permeability areas or something like that. It won't change just because of the deviated nature of the wellbore.

Q. Do you have an opinion, Mr. Dunn, as to whether or not, if the Commission grants Meridian's request to have twice the deliverability put into the order, that that, in your opinion, will allow the project to continue?

A. Yes, we would definitely continue with that.

MR. KELLAHIN: I have no further questions of Mr. Dunn.

CHAIRMAN LEMAY: Thank you, Mr. Kellahin.

MR. KELLAHIN: Perhaps it's proper at this time to move the introduction of Exhibit 1, pages 1 through 8, Mr. Chairman.

CHAIRMAN LEMAY: Without objection, Exhibits 1 through 8 will be admitted into the record. Mr. Lund.

MR. LUND: Thank you, Mr. Chairman.

EXAMINATION

BY MR. LUND:

Q. Good morning, Mr. Dunn. Let's first turn to page 3 of your exhibit book, please.

A. Let me get an exhibit book. Okay.

Q. That's a depiction of state deliverability data, is that correct?

A. That's correct.

Q. For the Howell area?

A. That's correct.

Q. Do you have any cumulative production information from the proration units in that area?

A. Yes.

Q. Do you have that in front of you or do you need to refer to something?

A. No, I would have to refer to something.

Q. Let me ask you this generally. In the center of Exhibit No. 3, you've got the Howell unit highlighted. Do you know what its cumulative production is?

A. Approximately 14 Bcf, I believe.
Q. What about the cumulative production just to the east of that, the proration unit in the west half of Section 13?
A. West half of Section 13? I couldn't tell you that one without looking up the data.
Q. Do you have the data available? My data indicates it's 5.2 Bcf?
A. That sounds in the range.
Q. Does that sound reasonable to you?
A. Uh-huh. Uh-huh.
Q. What about the cumulative production to the west of the Howell unit also in Section 14, the Florance unit?
A. I don't have the exact data. It's greater than 10 Bcf, I believe.
Q. How about 10.9 Bcf?
A. That sounds about right.
Q. So already in Section 14 you've got the Howell proration unit already producing 4 Bcf greater than the offset to the west, is that right?
A. That's correct.
Q. Let's go to the south of the Howell unit, going to Section 23. Do you know what the cumulative production is in the proration unit in the east half

of Section 23?

A. Not exactly, probably a little bit greater than 10, again, I would assume.

Q. How about 5.3 Bcf? Does that sound true to you?

A. I would have to look at that one. I don't know.

Q. And the proration unit in the west half of Section 23, the Howell one, do you happen to know what the cumulative production is there?

A. No.

Q. How about 7.9 Bcf?

A. That's reasonable.

Q. Does that sound in the ballpark to you?

A. Yes, it does.

Q. Finally, let's look at the proration unit in the west half of Section 24. Again, do you happen to know what the cumulative production is there?

A. No.

Q. How about 5.2 Bcf? Does that sound reasonable to you?

A. It could be.

Q. Does it sound reasonable, though?

MR. KELLAHIN: I'm going to object unless a foundation has been placed for this witness to say.

I don't want him to guess. If Mr. Lund has a witness who can give us the cum's, let's put him on. But if this witness doesn't know, it's not fair to have him guess.

CHAIRMAN LEMAY: I would agree with that. That's normally the subject of your own witness. "What is reasonable," I don't know what you're trying to get at.

MR. LUND: I would be happen to live with the ruling, Mr. Chairman, but he did testify that he was generally familiar with the cumulative production in the area.

CHAIRMAN LEMAY: Generally familiar with it, without knowing specifically what the offset tract does.

MR. LUND: Maybe I could just ask one question and move along.

CHAIRMAN LEMAY: Okay.

Q. Isn't it fair to say, Mr. Dunn, that the Howell unit that you were discussing has produced approximately 14 Bcf? That's already considerable greater than those offsets we've been discussing, isn't that fair to say?

A. It's fair to say for the ones you've discussed, that's true.

Q. And you were talking earlier about the competitive advantage of some of these offset wells. I just don't see that existing, given those cumulative production figures.

MR. KELLAHIN: Objection. That's argumentative.

CHAIRMAN LEMAY: Can you rephrase the question, Mr. Lund?

MR. LUND: The witness testified about a competitive advantage to the offsets of this particular drilling unit. I'm asking him how he can say that, given these cumulative production figures. I don't think that's argumentative.

CHAIRMAN LEMAY: Rephrased that way it's not. Continue.

Q. Would you answer that question, please, Mr. Dunn?

MR. KELLAHIN: Do you remember the question?

A. Could you rephrase it?

Q. Sure. Given the cumulative production figures we've been discussing, it appears that the Howell proration unit's cumulative production of approximately 14 Bcf is considerably greater than the other proration units we just went through. Is that a fair statement?

A. It's a fair statement that it is greater.

Q. Is 4 Bcf considerably bigger than production from an offset unit?

A. I think it depends on the area and what the ultimate recoveries are.

Q. All right. You don't think 4 Bcf is considerably greater. My question is, how can you say that the Howell unit, which is in the center of your Exhibit No. 3, is suffering a competitive disadvantage, vis-a-vis offset proration units, when it's cum'd 4 Bcf greater than the other offsets?

A. It's based on the fact that we produce at about half of our maximum rate than any of the offsets and, in many cases, a great deal less than half.

Q. So you have the current deliverability figures? Do you have the current deliverability figures of the offsetting units in front of you?

A. Exhibit No. 3 that you referred to earlier is that exhibit, the most current that I have available to me.

Q. Let's talk about those. Is that from February of 1990? Is that where those deliverability figures come from?

A. No. In most cases all these--well,

anything that we do not operate, I do not have access to any of the latest tests. Those all came out of the 1986 state deliverability books.

Q. 1986?

A. That's correct.

Q. Well again, looking at some of these offsets, let's look at the offset to the east in the west half of Section 13. Do you know what the current deliverability there? or even the 86 data I would accept.

A. For the proration unit for the east half?

Q. For the west half of Section 13, which is immediately offset to the east.

A. Approximately 875 Mcf a day.

Q. That's what my figure is, too. How about the proration unit for the west half of Section 24?

A. Approximately 600--over 600.

Q. That's fair. That's consistent with my data, too. How about the proration unit for the east half of Section 23, which is directly to the south of the Howell unit?

A. Approximately 700 Mcf a day.

Q. That's fair, also. How about the proration unit in the west half of Section 23?

A. Almost 400.

Q. 386?

A. That's correct.

Q. And then finally the proration unit directly to the west of the Howell unit, that being the Florance unit?

A. Oh, about 1.4 million a day.

Q. Again, my question goes to the competitive disadvantage that you stated that the Howell proration unit is currently suffering. You've got deliverability figures of offsetting proration units that are considerably less than what's the Howell's doing, don't you?

A. No. The deliverability of the Howell unit currently is 520 Mcf a day. Also, we haven't looked at all the acreage around it, of course, but in general you named one proration unit that had anywhere less deliverability, according to my calculations.

Q. What's the number, the 186 number for the Howell "E" 2? Where does that come from?

A. That's the current test for the Howell "E" 2.

Q. As of what date?

A. Middle of last summer it was tested.

Q. The information I have is at 4/28, but I don't know if that's current.

A. No, it's not.
Q. It's lower than that?
A. Correct. The 186 is the current test.
Q. All right. I think in your testimony you stated that you were to honor the 790 setbacks for the deviated well, is that correct?
A. That's correct.
Q. You would file deviation surveys with the OCD to make sure that it doesn't encroach on the 790 setback?
A. That's correct. That's all in the initial order that we said we accepted.
Q. You haven't changed that position?
A. No.
Q. Where are you going to perforate and produce the deviated wellbore in the Howell unit?
A. We won't know until we drill the well. We'll drill as far through the Mesaverde interval as we can, while staying within that drilling window, and we hope to be able to produce all that is productive within that interval.
Q. If it only looks productive in that one quarter section that the deviated wellbore encounters, would you only perforate and produce from that one quarter section?

A. If that was the case. We expect to be productive throughout, since we have wells in the north and south end that produce.

Q. I think you're talking about, you've got to look for increased permeability areas and additional sand lenses that you haven't encountered with the vertical well, is that right?

A. We hope to find those situations when we drill this well, yes.

Q. My question is, if you only encounter additional sand lenses and increased permeability in one quarter section that the deviated wellbore encounters, would you then just complete and produce only in that quarter section?

A. No, we would not. This is part of an overall idea to redrill the original well and to produce from throughout the Mesaverde formation.

Q. Let me ask you a couple of questions about the well costs. I think you testified that a vertical well would cost about $400,000, is that right?

A. To drill, complete and have facilities.

Q. And for a deviated wellbore, approximately $1 million?

A. Yeah. $985,000 is what I utilized in the economics.

Q. I was looking at the transcript from the prior hearing, and your drilling engineer--I believe his name is Mr. Falconi?

A. That's correct.

Q. --gave some figures about well costs, and they're different. I was just curious, were Mr. Falconi's figures not including facilities and things?

A. Facilities or completion. He, as I remember--and I don't have the transcript in front of me--was stating drilling costs. Basically, rough numbers, we can drill a vertical Mesaverde for about $200,000 and it will cost $6- to $700,000 to drill the highly-deviated.

Q. Those were the figures I was remembering.

A. That's right.

Q. The difference again is what, the completion facilities?

A. Completion and facilities are an additional plus or minus $200,000.

Q. Let's talk a little bit about the correlative rights issue and that's the only reason Amoco is here. That's what we've got concerns about. We think it's a great idea to do this technology.

I think you testified earlier that under the formula you proposed, the offset operators' correlative rights are going to be protected, is that right?

A. Today?

Q. Yes, sir.

A. Yes, that's correct.

Q. And I think you also testified that two vertical wells could very well give you the same protection as one of these deviated wellbores? Is that right?

A. No. What I testified was that the greatest that you're at risk for right now is what two vertical wells currently produce within the Blanco-Mesaverde Field. So we would cap it at that level.

Q. You haven't discussed what the cap would be yet, have you? Are you going to talk about that?

A. I can give you rough numbers to my knowledge what that cap is, what the highest deliverability in a proration unit is.

Q. You proposed some language for inclusion in the order which was a little bit different than what the Examiner had. Can you explain that?

A. It just requests that the cap be the highest state deliverability in a proration unit in the Blanco-Mesaverde Field.

Q. So you would look at just a traditional proration unit in the field and calculate the deliverability based on the two existing vertical wellbores, and whatever the highest is in the field, you would limit your deliverability to that?

A. That would be the cap, that's correct.

Q. Do you happen to know what the highest deliverability is currently for a traditional proration unit?

A. I think it's in the range of 16 million a day.

Q. What proration unit is that?

A. It's the Fields 2 and Fields 2A, and I can't give you the exact location. It's in 39, I believe. But I can get that for you.

Q. We would like to see that.

MR. KELLAHIN: May I approach the witness, Mr. Chairman? I can give him that location.

A. The Fields LS #2 and #2A wellbores are located in Township 32 North, Range 11 West, Section 25. It's operated by Amoco and it currently has a State "D" of 16,061,000. It would be 16 million.

Q. You would tie to whatever the then current deliverability is? If that goes up or down, you would tie it to that?

A. We would consider that stipulation, yes.

Q. I'm sorry, I don't understand.
A. At this point we're just suggesting the tie to this state deliverability, to this current one.
Q. What happens if the deliverability in that unit you referenced goes up or down?
A. It goes up or down, then.
Q. Would your deliverability in your unit go up or down accordingly?
A. It could. Are we talking in comparison, utilizing this data?
Q. What's your proposal, is what I'm asking.
A. Our proposal is to set our cap at this current highest proration unit deliverability.
Q. So it wouldn't change? It would stick at the 16 million?
A. That's the proposal, but it could change. We think the most fair and equitable proposal is to tie to this cap currently. As production decreases in any of the units, it's going to decrease in our unit for the same reason as reservoir pressures decrease, et cetera, as you produce reserves.
Q. We're talking about your proposal for deliverability in allowable calculations. That's what I'm trying to understand. You're going to set it at the 16 million and it's not going to change for your

units?

A. I think that's fair and equitable.

Q. I don't, but I just want to understand what your proposal is.

MR. KELLAHIN: Objection to the editorial comment, Mr. Chairman.

CHAIRMAN LEMAY: I agree.

MR. KELLAHIN: We get lots of flexibility before the Commission, but I object to that comment.

CHAIRMAN LEMAY: We do recognize the fact that lawyers are incompetent. If they wish to testify, they need to be sworn in.

MR. LUND: That's a well-known fact in the Commission's proceedings.

A. I don't know that it's unfair to discuss fluctuating up and down, though. I understand your concerns.

Q. Thank you. The current system now, as set up in the prorated pool rules, is that you look at deliverability from wells in the opposite quarter section, correct?

A. Could you rephrase that?

Q. You were talking about how you do the formula for establishing deliverability. Mr. Kellahin took you through about how you look at wells in opposite quarter sections and then you add those two together, isn't that right?

A. Correct. You would take the two existing wells in the proration unit and add them together.

Q. We don't have any situation in the field now where you've got a wellbore that goes through both quarter sections, do you?

A. No, we don't. That's why this is a pilot project.

Q. And it's a different situation?

A. Definitely.

Q. Final question about drainage. I think you testified earlier that you don't see a problem of drainage going out of your proration unit and draining nearby proration units, is that right?

A. Yes. I testified, as compared to a vertical well that could be drilled in this same proration unit, that the drainage radius should be similar at whatever location you want to speak about.

Q. So the wellbore encounters, what, two to three times the formation?

A. That's right.

Q. But it's not going to increase its drainage area in that section?

A. Radius. I guess the best example to

explain that would be if you were looking at vertical wells, an example would be that if you took a stack of pennies, let's say, and that stack of pennies represented the drainage radius of that vertical well, the well being in the middle of the stack of pennies. Well, when you took that vertical well and redrilled it as a highly-deviated well, what would happen, those pennies would be slanted. They would start stacking one on top of each other, and you would have a drainage radius moving longitudinally down this proration unit that's the same radius. It's just this stack of pennies.

Q. And again, I think Mr. Kellahin asked you this question: Meridian is not open to the possibility of coming back and reviewing a potential deliverability or an allowable situation, depending on the results of this deviated well?

A. I think the rules are that at any time anybody can propose that we come back and hear them, and we would come back, if it's proposed to come back.

MR. LUND: That's all I have.

CHAIRMAN LEMAY: Additional questions of the witness? Mr. Weiss?

EXAMINATION

BY MR. WEISS:

Q. One thing you didn't tell us. What do you forecast out of that well?

A. It's hard to forecast, and that's why we're doing it as a pilot project. The reason why, the permeability changes are drastic within the Mesaverde and the nine-section deliverability plat that we showed.

If you'll notice, there are ranges of deliverability from 200 Mcf a day all the way up to 12 million a day within a half a mile, so it's tough to forecast. We do not perceive that we are going to gain a high productivity advantage over a good vertical well that intercepts the same reservoir that this highly-deviated well is in.

Q. 12 million is what you're anticipating? Is that what you're saying?

A. Oh, no. I'm hoping to be able to get two to three times the rate to make it an economic project. But that's why we're drilling it to find out. In addition, the more important factor is that we also prove up additional reserves.

Q. How does that, let's say, two to three times, I still don't have a number for you. Give me a number, any number. I don't care. What do you think it's going to be? 500,000 a day? a million? two million?

A. No. I would guess greater than a million for sure, because we're getting--

Q. How does that compare to a well that's has a massive fracture treatment up in this area?

A. Most of the redrills that we're doing right now, which we do do massive hydralic fractures, produce one to one and a half million a day. The examples that we showed of the Howell "D" 3B and the Scott 2R are greater than three million a day.

Q. On your P/Z charts, were those redrills stimulated in the same manner as the first well?

A. No, they would be hydraulically fractured, where the original ones would have been nitro-type open-hole.

Q. I notice also you're drilling them both towards the south?

A. That's only because the original, the old well, is in the north. We would drill to the north or to the south--

Q. Why not east/west at some place?

A. Primarily due to--if we go east/west and stay within our drilling window, we lose--well, I don't know what that would be.

Q. On these leases, but surely there are some where you could drill east/west 3,000 feet, if you wanted to. I'm just curious.

A. If that situation existed, we would definitely take that into consideration.

Q. As you test these wells, is it possible to test the pressure in each individual plot pod or lands as you call them? I'm just curious if there's anything to support the fact that there's no flow across pod barriers, such as you've assumed, or these lens--

A. The only support, and we'll kind of talk about this a little later, or somebody else will, that I have in my hands right now, one of the two redrills that we did, prior to redrilling it, produced condensate. And after drilling it we came in with what is really oil. It changed from like a 49-degree gravity down to in the 35 to 40 range. So, we picked up a pod of oil that wasn't in the first one.

Q. Then on your economics here, I didn't pick up what the price of gas is going to be.

A. I used--well, it doesn't really matter because these are incremental, basically, economics. I'm showing a break-even point.

Q. I understand, but it has a great deal to do with that break-even point.

A. No, because they're incremental to each other.

Q. Well, any break-even point, I think, is fixed, and depending on the price of gas and what it cost to drill the well--

A. It would fluctuate somewhat. I ran sensitivities on gas prices and some other things, and basically the point of the exhibit is not to show that 2.7 is exactly the break-even point. There's lots of assumptions that could be maneuvered, including the initial rate of the vertical well. The point of the economics is to show that we have to have a drastic increase in rate, whether it's two-fold, three-fold or four-fold, to make this an economically viable project for us.

Q. And the price you used on that graph?

A. That was SEC pricing that we use for--

Q. I don't know that what an SEC price is.

A. I'm trying to remember that right now. It's flat pricing, and I'm trying to remember it. It's something like $1.60 an Mcf.

Q. On your figure 3, down in Section 22--

A. Yes, sir.

Q. --I see the deliverabilities of those wells are quite high?

A. That's correct.

Q. Were they completed differently than your low permeability wells wells, do you know?

A. I can't speak specifically on that. In general, the wells such as in Section 22, the Florance 45, is probably an older well and would not have an identical hydraulic frac stimulation as the Florance 45A did.

I guess the answer to that is, I can't speak totally on that. The open-hole wells that were drilled in the 50's would be drastically different from newer wells which were hydraulically fractured. So, depending on the age of the well, there would be differences.

MR. WEISS: That's all I can think of at this moment. Thank you.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Mr. Dunn, it looks like you're going northwest to southeast with that, or is that because that section is tilted? I'm trying to understand if you're going straight north/south in the section or taking some kind of an angle?

A. What we're depicting there is a due south line. That's because that section is tilted a little odd. The wellbore that's depicted there is due south.

Q. I have the same concern on your prices that Commissioner Weiss had. Maybe a subsequent witness will touch on some economic scenarios there. What you're trying to show, as I understand it, is a deviated hole is going to cost more; therefore, you need an incentive allowable to justify drilling? Is that right in a qualitative sense, not necessarily quantitative?

A. That's right, along with to help with the risk that we see in drilling the well.

Q. The risk, as you're explaining it, is financial risk of the cost of the wellbore, as well as any contingencies that you might run into?

A. It's a combination of that risk and the risk that we will not increase recovery, that we've gone out and spent an extreme amount of capital for a project that ends up being uneconomic. That's what we're trying to prove about the new technique.

Q. Do you plan to frac that well?

A. It depends. In the Mesaverde, if the productivity isn't high enough you definitely go in and fracture. There are wells that do not have to be fractured to produce.

Q. But the diagonal well, is the technology there any different from fracking a diagonal well than a vertical well?

A. Yeah, it's different, and it would cost more again. And that is not included in these cost estimates, but, yes, it would cost more and is more difficult to do.

CHAIRMAN LEMAY: Mr. Weiss?

MR. WEISS: I have one more.

FURTHER EXAMINATION

BY MR. WEISS:

Q. Were there incentives provided to do massive frac jobs on these newly drilled vertical wells?

A. Not that I'm aware of, no.

Q. Then, I, frankly, don't see a hell of a lot of difference between a massive frac, where you spend maybe a million dollars on a frac job, and this.

A. That comparison, in fact, I utilized in the first hearing. There is some truth in that. That's why we feel like the original ruling is unfair because it's less than even the current standards.

What we are proposing, what is fair and equitable to us, first of all, is that that first ruling is not fair and equitable, and second of all, the two times the "D" is a reasonable request based on that this well would roughly develop the full 320 acres.

Q. Here is looks to me like you have control of your fracture and maybe you wouldn't the hydraulic fracture, the direction of it. And the costs are, maybe, comparable between this and a massive hydralic fracture?

A. I couldn't really speak on that. I would think this is more expensive in the long run, really, and also I guess the rest of the theory in terms of why we would want to do a highly-deviated well versus just go out and do a massive hydraulic frac, is that that fracture is going to go one direction, basically, and what is the chances of that fracture hitting versus us doing this, you know, longer-reach wellbore.

Q. Here you have control?

A. Right.

MR. WEISS: Thank you.

CHAIRMAN LEMAY: Additional questions of the witness? If not, he may be excused.

Let's take a 15-minute break.

One additional thing. Mr. Lund, you won't present testimony or statements in the case?

MR. LUND: Sounds like maybe we have to,

given the production data.

CHAIRMAN LEMAY: Well, I think we can understand your position. Our concern is that without any of the witnesses, we have no counter proposal from Amoco as to what the formula should be. And actually that would be helpful if you're opposing the case.

MR. LUND: We would be happy to do that.

CHAIRMAN LEMAY: Thank you.

(Thereupon, a recess was taken.)

CHAIRMAN LEMAY: We shall continue. Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Chairman. At this time I would like to call Mr. Greg Jennings. Mr. Jennings is already under oath as a witness. He's a petroleum geologist with Meridian in Farmington.

GREG JENNINGS

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

EXAMINATION

BY MR. KELLAHIN:

A. For the record, Mr. Jennings, would you please state your name and occupation?

A. My name is Greg Jennings. I'm a senior geologist for Meridian Oil in Farmington, New Mexico.

Q. Mr. Jennings, have you participated as a petroleum geologist for your company in this study group of technical people to evaluate the feasibility of a highly-deviated wellbore in the Mesaverde prorated gas pool?

A. Yes, I have. George Dunn and myself and a few other people have worked on this for 9 or 10 months.

Q. Did you testify before Examiner Catanach in the Examiner Hearing of this case?

A. Yes, I did.

Q. You presented to him your geologic interpretations and conclusions in that manner?

A. That's correct.

MR. KELLAHIN: Mr. Chairman, at this time we would tender Mr. Jennings as an expert petroleum geologist.

CHAIRMAN LEMAY: His qualifications are acceptable.

Q. Mr. Jennings, I'm not going to ask you to repeat all your geologic interpretations and conclusions that you presented to the Examiner, but I would like you to give us a clear understanding of the geology, as you interpret it, with the Mesaverde reservoir in this pool, and explain to us why you, as a geologist, conclude that the pilot project for these two wells is a necessary project.

A. Well, the first exhibit, which is a cross-section A to A', I'll actually illustrate a couple of points from this exhibit. As you're all aware, the Blanco-Mesaverde pool was originally developed in the 1950s on 320-acre spacing, and then in-filled in the 70s on basically 160's. There really is a drastic difference in the drilling and completion techniques used for the old wells versus the new wells. You can visually see it on this cross-section. The cross-section--

MR. KELLAHIN: Excuse me. It should be page 9 of the exhibit book.

MR. WEISS: They're mislabeled. This says B to B'.

MR. STOVALL: Your exhibit says B to B'.

THE WITNESS: I'll have to take that up with the drafting department when I get back.

Q. All right, Mr. Jennings. Continue.

A. This is a north/south cross-section through the Howell section, it's Section 14 of 30 North, 8 West. It includes the old well drilled in the 1950s, the Howell "E" 2, and two wells drilled in the 1970s. The old drilling method was to drill right to the top of the massive Point Lookout, TD the well, set production casing to the lower part of the Cliff House, the massive Cliff House, and generally they completed these wells, open-hole, with nitro.

The new wells, as you can see, drilled 3- to 400 feet deeper in the Lower Point Lookout, set production casing through the entire section, and then a two- to three-stage frac perfed and stimulated the entire section. You've got significant interval that was not completed in the original well, in the older wells, and furthermore the inefficient stimulation that was done in the 1950's gives you a basic inequity between the wells that are drilled in the 70's and the wells that are drilled in the 50's.

This really is the basis for our Mesaverde redrill program. We recognize that those old wellbores are not adequately draining their spacing units, and George can--well, George has discussed that already. It's a function of the way the wells are drilled and completed, but it's also a function of the variability in the reservoir quality, and the cross-section shows that.

Basically, I've colored the sandstone pay greater than six percent density porosity, standardized it to a 25-zone resistivity cutoff where resistivity logs are available. You have a net pay map, a little one on the cross-section, and if that will work, that will speed things up by not getting into the bit net pay map.

The only thing I really want to show you here is that there is significant variation in matrix porosity over short distances. I believe the range on this map is from a low of 130 feet to a high of 182 feet in total net pay in the Mesaverde group, and that consists of multiple thin sandstone lenses that blossom and pinch out from well to well.

Q. Let's look at the net pay map for a moment. When you look at the net pay map, are you mapping the net pay with a porosity value greater than six percent for the entire Mesaverde pool interval?

A. Yes.

Q. When you look at the individual lenses that make up the Mesaverde formation on the stratigraphic cross-section, can you correlate each of those lenses that have porosity values of six percent or greater from wellbore to wellbore?

A. No. Certainly some are continuous, but, for the most part, there's a lot of discontinuity. It's a very heterogeneous reservoir.

Q. When you look at the relationship of the original well and the in-fill well in the Howell spacing unit, what do you conclude as a geologist with relation of the availability of the in-fill well to encounter and therefore potentially produce reserves that are not exposed in the wellbore of the original well?

A. I believe that there are additional sand lenses, if you will, between the two in-fill wells--between the two wells in the proration unit that have not been penetrated and are not in communication with the two wells in the unit. Therefore, they do not completely drain all of the reserves within that 320-acre unit.

Q. Are you, as a geologist, confident that you can map the Mesaverde lenses between those two wells, that you're going to know in the absence of drilling the highly-deviated well, whether or not you're going to get additional reservoir out of the Mesaverde?

A. Well, I'm confident that I cannot predict with accuracy the degree of variability from one end of the section to the other end.

Q. Can you, with confidence, map the wells in the spacing unit with wells off the spacing unit?

A. Not to the degree of accuracy that we need to figure out where all the pay is. It's really even further exemplified, if we could move to this next exhibit, which is basically the same thing, a cross-section and net pay map for the Riddle area, which is the other cross-section in your book, it's even a more drastic exemplification of what's going on.

Here we have variations in net pay from a thin of 112 feet to a maximum of 275 feet in a little over a mile. I was even surprised when I put this together. I think it's quite obvious that we have large variations in matrix porosity from well to well. This doesn't tell the whole picture.

Number one, you have some drastic variations in net thickness and in the continuity of the reservoirs. But this doesn't correlate on a one-to-one basis, by any means, with the drastic variations in production. There are wide variations in production in these wells out here, and it's more a function of the lateral changes in permeability. This is a fracture-enhanced reservoir, and all I can map from logs is matrix porosity. And the fractures, and those areas of higher permeability are the real key to the enhanced productivity. It's quite common to find some of the thinner net pay wells with the best production.

Q. What do you, as a geologist, hope to gain, that you don't already have, with the information that results from drilling and completing the highly-deviated wellbores?

A. Well, I believe that, and really it's been proven, that there are these regions of fracture-enhanced permeability that exist sometimes very close to the existing wellbores. Two cases in point George has already touched on. One was the Scott 2R. We had a Mesaverde well that was completed in the 50's, had cumulative production of roughly 3 Bcf in 30 years.

Another well, the Scott 2R, was drilled 2- to 300 feet from that old wellbore. It took a kick in the Upper Cliff House and the well came on line for 10 million a day and cum'd 6 Bcf in five years. So, in five years that new well had cumulative production of twice what that old wellbore had in 30 years. That well is still making four million a day. Just from a rate standpoint, it's pretty obvious that that well encountered some new reservoir.

The other case was the Howell "D" 3B, which here we had an old Mesaverde well drilled and completed in the 50's that had cum'd 12 Bcf and 10,000 barrels of condensate, 50-degree gravity. Actually, it was a Dakota test drilled 300 feet from the old wellbore. They took a kick in the Lower Point Lookout and TD'd the well there and completed it in the Mesaverde, put it on line for four million cubic feet a day, and 100 barrels of oil. Now we had 30-gravity oil. In addition, high reservoir pressure. These are 2- to 300 feet away from the old wellbore.

So we know that there are these areas out there that have additional pay, fractures, pockets of higher permeability. But I can't map them. We could drill 5 or 10 vertical wells in this section and we may get lucky and tap into it as those two examples did. But the odds are that we won't. This, really, is the whole crux of the high-angle project. We know that those regions are out there in our proration unit. We know that the existing two wells, in all likelihood, will not drain the reserves that are in that spacing unit. Therefore, you have waste occurring, and we think this technique will significantly increase the chances of encountering those fractures in those regions of higher perm simply by exposing a much larger amount of surface exposure to the rock.

Basically, what went to do is find those areas that other people have found by good fortune; we want to finds them by design. We believe that if we initiate this project and are mechanically successful, which is by no means a guarantee. It's never been done in the Western United States and only, I believe, two in the whole U.S. If we are successful, we believe that we will tap into those additional reserves and basically increase the ultimate recovery from the proration unit and prevent the waste that will occur if some type of technique is not employed to recover those reserves.

Q. Let me ask you as a geologist, Mr. Jennings, whether or not you can, with confidence, provide an accurate net pay porosity map for the Mesaverde that then can be used by the engineers to make volumetric calculations so that we could draw some comparisons between what volumetrically is the gas in place underlying a specific spacing unit and compare that to what it may have cum'd or produced over time? Now can you, as a geologist, give the engineer a map that you think is reliable from which, then, he can make those types of calculations?

A. No. It's partly attributable to the great lateral variations in matrix porosity, but to a larger extent it's because of the fracture component of the reservoir. It's just simpy unpredictable and does not fit in the volumetric calculations.

Q. So if an engineer is going to work with some cumulative production numbers, you're telling me as a geologist you have no way to assist him in this reservoir in telling him where that gas came from?

A. Correct.

Q. If he has some P/Z calculations where he's given you what he projects this individual wellbore is ultimately going to cum, you're unable to assist him to accurately map where he gets that gas?

A. Yes. I would rather be in the thicker part of the pay, but it's only a small part of the reservoir picture.

Q. And you can see from looking at the various cumulative producing volumes for this spacing unit and all of the rest of the spacing units in the pool, that there is quite a range of cumulative productions, aren't there?

A. Definitely.

Q. Is there a direct geologic correlation, then, to either cumulative production or deliverabilities and the thickness in reservoir volumes from which they produce that gas?

A. No.

Q. You have prepared, under your direction and supervision, the other geologic interpretations that are shown in the exhibit book?

A. Yes. And all those are are a larger version of the net pay map and you can peruse those at a later date if it will help you. Your copy of that map is pretty small on the cross-section.

MR. KELLAHIN: Mr. Chairman, at this time we move the introduction of Mr. Jennings exhibits on pages 9 through 12 of the exhibit book, and that concludes our direct examination.

CHAIRMAN LEMAY: Exhibits 9 through 12 will be admitted into the record without objection. Mr. Lund.

MR. LUND: Just a couple if I may, Mr. Chairman.

EXAMINATION

BY MR. LUND:

Q. Mr. Jennings, your testimony about the 1950s wells versus the 1970s wells, what was your conclusion, that the 1970s wells are more likely to be better producers? Is that what you testified to?

A. My conclusion is that the old wells did not drill to the bottom of the pay, didn't complete in the top of the pay, and because of an efficient completion technique, will not and now the mechanical condition of the bore hole, because of the caved-in nature of it, will not produce the reserves that are in that 160-acre unit.

Q. That's why so many of the original, parent locations have been redrilled with better technology?

A. That's correct. That's why, when you consider that over half of the wells in the basin are the old wells, and think of every one of those 160's as having additional reserves that will not be drained, it's a very big picture.

Q. On your Exhibit No. 12, just a quick question. You're showing an isopach net pay map for the Riddle drilling unit. Isn't it true that the original well to the south part of Section 4 has been plugged and abandoned in the Riddle?

A. In the southeast quarter of Section 4?

Q. Yes, sir.

A. That's correct.

Q. Yet you're showing better pay there than you do to the north of the section, don't you?

A. This map was constructed using roughly two wells per section, which are the modern logs. The old logs, which are basically induction logs, you can use them to a minor degree, but you get a better degree of accuracy if you use the modern logs and simply interpolate between the data points. So the old wells in the section, such as that one, were not used because of the innacuracy of the old logs.

Q. Has Meridian considered doing a redrill of the vertical well in the south?

A. Yes, we have considered it. It is one of many old wellbores that was P & A'd because of non-commercial daily production. And, yet, we don't believe that that well has produced all the gas in that 160-acre tract and is a good candidate for a redrill.

Q. For a vertical redrill?

A. Frankly, if this type of technique would work, certainly we don't plan on stopping after two wells if it's successful.

MR. LUND: Thank you.

CHAIRMAN LEMAY: Additional questions of the witness? Mr. Weiss?

EXAMINATION

BY MR. WEISS:

Q. You mentioned this is a fractured reservoir. Is that the same as a naturally fractured reservoir?

A. Yes.

Q. You also said there have been two other deviated wells drilled?

A. Yes. And I--
Q. Where were they?
A. --I don't know all the details. I know that the federal government conducted a research well, I believe, in Pennsylvania, and I really don't know that many details on it. Perhaps Louis, who will come after me, might know something about the other well. Very little information is available; basically a very risky technique. However, we believe that because of our experience in other areas, such as the horizontal Bakken play in the Williston Basin, that we can do it.
MR. WEISS: That's all I have. Thank you.

EXAMINATION

BY CHAIRMAN LEMAY:
Q. Mr. Jennings, I have a question that maybe Mr. Jones might be more qualified to answer, so if he is just defer to him, but you're laying an assumption that you have sands in here that have not been drained, as I understand?
A. Correct.
Q. And need to be contacted with the wellbore on a diagonal well. Do you happen to know the initial bottom-hole pressure of this field?
A. Roughly 1,500 pounds, I believe.

Q. Do you know the current bottom-hole pressure?

A. Roughly 400 pounds.

Q. Would you expect, or are there examples of wells when they've redrilled the 320, they've encountered virgin pressures?

A. Not to my knowledge. That gets back to your earlier question. If you could isolate the zone, perhaps you could measure some higher reservoir pressures. What you're looking at is a 1,200-foot section of rock with one, perhaps, small area that does have less-drained and less-depleted reservoir and, therefore, will give you a higher reservoir pressure. Really, I am getting out of my area of expertise but, no, I do not know of any wells that have been redrilled and encountered completely virgin pressure.

CHAIRMAN LEMAY: I might pick that up with the next witness. Thank you very much. I have no further questions.

Call your next witness.

MR. KELLAHIN: Mr. Chairman, at this time I would like to call Mr. Louis Jones.

LOUIS JONES

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

EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Jones, for the record, would you please state your name and occupation.

A. I'm Louis Jones, regional production manager for Meridian Oil, Inc., in Farmington, New Mexico.

Q. Mr. Jones, did you testify as production manager of your company before Examiner Catanach when he earlier heard this case?

A. Yes, I did.

Q. On prior occasions have you testified as an expert in New Mexico prorationing matters before this Commission?

A. Yes, I have.

MR. KELLAHIN: We tender Mr. Jones as an expert production manager with particular expertise in New Mexico proration.

CHAIRMAN LEMAY: His qualifications are accepted.

Q. Mr. Jones, you've had an opportunity to participate in this case and you have seen and reviewed the Examiner Order entered by Mr. Catanach. In your opinion, Mr. Jones, can Meridian go ahead and institute this pilot project in either one of these areas in the absence of modifying that order?

A. No, sir, we cannot. We do not feel like it is certainly economically justifiable with the current ruling as such. We're obviously concerned about our ability to flow this well after we've spent a tremendous amount of capital and taken the mechanical risk. When we feel we have an alternative, with the two times the "D", along with the cap. We think that's very important. That's a major change from our last hearing.

Q. Examiner Catanach was not afforded the opportunity to decide the case based upon our presentation of a cap or an upper limitation?

A. That is correct.

Q. As an engineer with expertise in prorationing matters in New Mexico, Mr. Jones, would you simply give us an example of how the system currently works and what is the problem in allowing the highly-deviated well to operate only with taking a single times the deliverability of that well and integrating that into the allowable for that well?

A. Right. I have an example on page 13, but what I would like to do is kind of summarize again how the allowables are determined. Using this proration unit, which is 320 acres, you obviously get to take each one of the deliverabilities, or the two, in this case, and add them together to get a combined "D" for that proration unit. Then your allowable for that proration unit is determined by the D's. It's a function of those D's that are generated from the two wells.

So you get to add two vertical wells to give you the addition for the total "D" for that proration. Now, what we're asking for is because we'll have one well within that 320, we're asking for two times the "D" of that one well. It's essentially, to me, not much different than exists today because we have the opportunity to have two D's within the same proration unit or the 160-acre spacing as was mentioned earlier.

What I've done, I put an example in the book to give you an idea of how a well could be affected. It was asked earlier what we may expect out of the well. I went ahead and I assumed 2.7 million a day. Do we expect that? We certainly hope for it. We're not exactly sure what to expect because, obviously, this is a pilot project.

What I've assumed here is that our "D" is equal to "Q," which is the rate of the well. That's the well test data of 2.7 million a day or 2,000 Mcf per day. If we take the total allocations for the Mesaverde pool for 1990, and I just assumed that they would equal 163 Bcf for the entire pool, then they would be 12-percent higher than our 1989 numbers.

I've done that, Mr. Chairman, to try and show what I think is a best guess. I think our allocations will go up in 1990 for the pool. I've tried to be as realistic as possible on this example. I've also assumed that the well would decline at five percent per year. I think that's a reasonable assumption for the Blanco-Mesaverde and the San Juan Basin. And then I've showed that what exists today with the ruling of one times the "D" for the entire proration unit.

If that occurred, all these assumptions hold true, and I feel they are our best guess. And we could produce this highly-deviated well for 7.5 months, straight, at which time it would be 12 times overproduced. After that, you could keep the well under the current rules and regulations at 11.9 times overproduced by producing it only four and a half months out of the year. It just gives you an example of what the proration in the Blanco-Mesaverde in the San Juan Basin can do, as far as your applicable production.

Q. If that type of allowable restriction is left in place, then is Meridian going to be able to justify the economics of spending the money in order to develop these as pilot projects?

A. No, sir, we would not. Without some type of assurance of continuing to flow these wells and recover our capital expenditures and, of course, the mechanical risks that we take, we would be much better off going and drilling a vertical wellbore.

Q. Based upon your knowledge and experience and your expertise in this particular area, do you conclude that Meridian will enjoy an unfair advantage over Amoco or anyone else that does not have in offsetting spacing units a highly-deviated well?

A. I do not believe so, for a couple of reasons. First of all, they have the opportunity to do the exact same thing. The technology is out there. But secondly, we've added a cap, and that cap is what exists today and has existed for 35 years. I'm saying it's no more of an unfair advantage than has existed the last 35 years. I think that cap certainly will give Amoco, I hope, and other offset operators, at least some comfort on their protection of correlative rights.

Q. Describe how the mechanics of the cap would work.

A. This was brought up earlier. Meridian would be willing to move that cap, with time, to just match the highest proration unit in the San Juan Basin, Blanco-Mesaverde pool, of vertically drilled wells as it exists today, because we could go out today and drill two vertical wells and maybe even exceed the highest that exists today with Amoco. But we are willing to float that.

If the 16 million a day proration unit drops to whatever, 10 million, 8 million, then we want to go back to the highest proration unit existing by any operator, not just Amoco, obviously, but by any operator in the Basin, and maybe Meridian.

Q. Do the mechanics of prorationing in the Mesaverde pool allow the deliverability of a spacing unit to be set by the corresponding deliverabilities of the offsetting spacing units?

A. What the request is, is that we take two times the deliverability of the highly-deviated well. Let's use this example. For example, "D" is equal to our rate of 2.7 million a day. What we're requesting is that we utilize two times the "D" of that well. So, in this case, it would be 5.4 million a day as a "D", and that would be the "D" for that proration unit, not the 16 million a day. We're just using the 16 million a day to give comfort. That could be the peak. Obviously we would like to make as good or better well than what I've shown here. We would like to have some of that upside. But we are also limiting our upside with that cap that exists out there today.

Q. Why shouldn't that cap be reduced to a point where it doesn't exceed the offsetting combined deliverabilities of the Amoco spacing unit, for example?

A. Under the current rules and regulations, that's the way it exists today and has existed for 35 years.

Q. That's simply because we use deliverability as one of the components by which we set the producing rates for the pool?

A. That's correct.

Q. There already exists, does there not in the Basin for this pool, Mr. Jones, wide ranges of disparities in deliverabilities that are used between and among wells?

A. Wide ranges of deliverabilities and wide ranges of cumulative production. And it's a function of the permeability and the amount of pay that is intersected with the wellbores.

Q. Would you, as an engineer with experience in this area, Mr. Jones, be willing to have Amoco do what you propose to do in this case?

A. Absolutely.

Q. Without reservation?

A. Yes, sir.

MR. KELLAHIN: No further questions, Mr. Chairman.

CHAIRMAN LEMAY: Thank you Mr. Kellahin. Mr. Lund.

EXAMINATION

BY MR. LUND:

Q. Mr. Jones, as I understand your testimony, the only difference from the hearing before the Examiner was your proposal that you've raised today to put a production cap?

A. That is correct.

Q. And is it still your feeling that you need some sort of guaranteed economics to make this drilling project viable for your company?

A. That is correct.

Q. You're participating in a study committee, aren't you, for New Mexico, that's looking at the prorated pools and potential solutions to some of the problems that have arisen?

A. Yes, I am.

Q. Isn't it fair to say the real problem we're talking about here is the allocation system that allows deliverability to be calculated?

A. Well, obviously it's part of the proration system. We are certainly concerned about the ability to flow the well after the capital is spent.

Q. Well, look at your Exhibit 13.

A. Okay.

Q. You're setting forth there the problem with the way the allocation system works now and how you run into the 12 times overproduced rules therefore requiring a well to be shut in?

A. Yes, sir.

Q. And everybody is facing that problem, aren't they?

A. Yes, sir.

Q. All the offsets to the units you've been describing are facing that problem?

A. Yes, sir.

Q. But yet you want some special rules for your two units as opposed to what the offsets are

getting, don't you?
A. We are asking for a special allowable to justify the risk.
Q. All the offsets are living with those prorated pool rules and yet you want a two times deliverability factor for your two proration units?
A. It's two times the deliverability of one well.
Q. Of the deviated well?
A. That is correct.
Q. You think that's fair?
A. Yes, sir.
Q. Why?
A. As I stated before, it's essentially 160-acre spacing now and we're covering 320-acre spacing. With this two times ruling, if accepted, it would give us the comfort to go ahead and spend the additional dollars necessary to test this pilot project.
Q. No other operator in the pool gets two times the deliverability factor for one, do they?
A. Not for one well, but they get two wells within the proration unit.
Q. Now, you stated earlier that there's no violation of correlative rights because all the

operators have the opportunity to do the same thing you're proposing, is that right?

A. The technology exists, we believe.

Q. Yet you and your witnesses have spent a lot of time talking about how risky this is, how expensive it is, and how many problems could result?

A. Yes.

Q. You think it's fair for us to take the same risks in an unproven technology?

A. Oh, I think what we're asking for is certainly some guaranteed economic justification for testing.

Q. I sure understand that's what your position is. You also testified that with the cap that you propose, that's the same thing that's been happening for 35 years?

A. I'm saying there's no more risk to the offset operators than exists today in the Blanco-Mesaverde pool. You have that same risk today if I go out and drill a vertical well. In fact, it could be 20 million a day "D." The reason we through in the cap, obviously we were trying to give comfort to the offset operators, that we'll take the cap for the current proration units that exists today that have been vertically drilled. We're looking for a way to make this more palatable. Obviously the concerns are the correlative rights.

Q. Sure, and that's why we're here, you know. We think it's a great idea. I don't think that's really fair, and let me ask you this. You say it's the same thing that has been in existence for 35 years, but nobody gets a two times "D" factor for any one well?

A. When I say it's the same thing that's been in existence, I'm saying that offset capacity for that proration unit to produce at that level to get that allowable has existed, and it still exists today.

Q. That's the other factor you're cherry picking in your proposal, because you're proposing that you look at the highest deliverability from any proration unit in the entire Blanco-Mesaverde pool and match that highest for your two deviated wellbores?

MR. KELLAHIN: Objection to the characterization of this as "cherry picking." I think that's argumentative, Mr. Chairman.

CHAIRMAN LEMAY: It is. All's you have to do is start out with "are you," and then your statement, rather than being argumentative by saying "you are." Just reverse the pronouns there.

MR. LUND: I did not mean to be

argumentative.

A. We are willing to place a cap equal to the highest proration unit that exists today.

Q. The difference is, what you're looking at now is, you're looking at your direct offsets for terms of correlative rights consideration, isn't that true?

A. Could you restate that?

Q. Sure. Right now, when you're concerned about correlative rights, you look at your offsets and see what they're producing, correct?

A. Yes, sir.

Q. Then you can take appropriate action depending on what your offsets are producing?

A. Yes, sir.

Q. Under your scenario, that's not going to be the case anymore, because instead of looking at your direct offsets you have to be concerned about the highest deliverability proration unit in the field?

A. Yes, sir, that's what we're asking for. Now, realizing that I think it's a very, very small probability that we'll ever meet that cap. We hope to, but I think it's a small probability that we would meet it. We certainly want it there for our economic justification to go drill these wells.

Q. The final question. You're going to move your deliverability up and down depending upon what the highest proration unit does?

A. No, sir. We take two times the deliverability of that well. Let's say the well tested at 2.7 million a day. The deliverability for that proration unit would be 5.4 million a day, assuming that 5.4 million a day is no larger than any existing proration unit in the Basin today.

Q. So if the highest deliverability of any proration unit in the basin was 2, you would not exceed that for your deviated well?

A. The cap would be 2, yes, sir.

Q. It would move up and down?

A. Yes, sir, as long as the 2 times the "D" was affected by the cap.

MR. LUND: I was confused about that based on your testimony. Thank you very much.

CHAIRMAN LEMAY: Any additional questions of the witness? Mr. Weiss.

EXAMINATION

BY MR. WEISS:

Q. Is a hearing required if you want to do a massive frac job, I mean, pump a couple million pounds of sand in a well?

A. No, sir.
Q. How is the "D" calculated on a well out there if you do a massive frac?
A. It's calculated the same way as the existing formula. I don't have the formula with me, but it's a function of rate and pressure draw down. In most cases throughout the Basin, the "D" equals the "Q." That's a pretty good assumption.
Q. I didn't phrase my question properly. Let's say you drill a third well, one of them is bad, is damaged, you can't use it anymore, on 160 acres, you drill a third well, and you spend a million dollars fracking.
A. Yes, sir.
Q. What is that "D" based on? Which well? That well? two wells? three wells?
A. No, it's that well. But you get that well plus the other well on a proration unit added on top of it.
Q. Do you think--
A. So you still get two wells out of the 320.
Q. You mentioned the "D" was dependent on the quality of the sand and the porosity. Do you think it's dependent upon the amount of money you spend on the completion?

A. No, sir, it really depends on the type of rock that you intersect, in most cases.

Q. If the "D" were based on the best two out of three wells on a 320 acres, would Meridian drill a horizontal well or deviated well?

A. We feel like the two times is justification for us to drill. That's what we're asking for.

Q. I didn't hear the answer to my question.

A. I cannot answer that at this time. I think that the two times the "D" is a justification that we would need to drill the wells.

Q. I had a question on the cap also. Let's say this deviated well comes in at 25 million a day and today the maximum "D" is 16 million a day.

A. Yes, sir, for proration.

Q. Next month, what would the cap be?

A. The proration units, their deliverability changes every two years unless they are retested for some reason, such as workover, reperforating, et cetera. The "D" of 16 million a day was predicated on the 1986 program that took effect in 1987. We have some new tests that will take effect April 1, 1990. I do not know what that maximum is at this time.

Q. It's conceivable, then, that that cap could change to what you've deviated?

A. I fully expect that cap to change, and I fully expect that cap to go down.

Q. Would you expect it to change to the 20 million a day out of the deviated well?

A. No, sir. My best guess of what I think the cap would change to, let's say April 1, would be in the 12 million a day range. That's what I'm expecting out of the vertical wells in the current proration units. Obviously, if you drilled a 25 million a day highly-deviated well, we would be limited to the 12 million a day.

Q. For the two years or for a test period, and then it would go to 25?

A. No, sir, we're saying we would always float with that.

Q. Wells other than the deviated wells?

A. Right, the vertical wells.

Q. If you would look at Exhibit 3 there, on Section 22?

A. Okay.

Q. I see that the deliverability on the west half of that section is about six times that of the east half. How are correlative rights handled there?

A. There are wide variances in deliverability and cum's throughout the Basin, and the proration system has been in place for many years in an attempt to protect correlative rights, in an attempt to afford everyone the opportunity to protect their correlative rights.

Obviously, in this case, the offset operator has a current advantage if he wants to produce his gas. He can produce more gas under the allowable system than we can in the east side of the proration unit at this time. That's a current advantage. Now, I'm not looking at the history. Obviously that was brought up earlier.

MR. WEISS: That's all the questions I have. Thank you.

CHAIRMAN LEMAY: Thank you, Mr. Weiss.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Did I hear you, Mr. Jones, say that you thought reserves were based on the amount of pay or that was a factor encountered in the wellbore, the amount of productive sand encountered in the wellbore, was one function of the reserves under prorationing?

A. It was a function, yes, sir.

Q. As I understand a previous witness, I thought he'd made the comment that it has nothing to do with the amount of reserves recovered under a proration unit?

A. It's not the only thing that affects the production in the cumulative recovery from that proration unit. Obviously variations in permeability, fracturing, play a major part in the total recovery from that proration unit.

Q. Following up, you have been certainly involved in this field for some time, both with Tenneco and with Meridian. Under the in-fill well drilling program, have you encountered any wells that have had some virgin pressure on the in-fill program?

A. Most of our in-fill wells have been in the middle of the Basin where they've been produced, where the Mesaverde has been produced for many, many years in the better quality areas, because these are redrills of old open holes. The old open-hole technique was utilized in the middle 50's and they drilled up the best part of the reservoir first.

So I feel like we are intersecting lenses that may have virgin pressure. Whenever you perforate the entire interval you do not see that, because then you're in communication with the rest of the intervals in your wellbore. We don't have the documentation that we have virgin pressure in any one piece. I feel like that's a good possibility. It becomes much more of a possibility as you move to the edges of the Basin where the Mesaverde gets tighter. I believe this technique has a tremendous potential, particularly on the edge of the basin, where the vertical Mesaverdes now are not profitable.

Q. The assumption I'm trying to get at is that you have these sand lenses that have not been intersected by a wellbore.

A. Yes, sir.

Q. Or an alternative, I guess, can't find a way to drain to fractures that set at or to a wellbore.

A. Yes, sir.

Q. I would expect, unless you're taking gas out of one zone and putting it in another zone acting as a fee zone, that when you drill an in-fill well, occasionally you would intersect some of these sands and they would have close to virgin pressure and you would be able to see that, if those sand lenses had not been drained in the past?

A. We don't have the measured data for virgin pressure. We have seen higher pressure intervals. I think we showed that earlier on the P/Z.

Q. In a production sense, yes. Do you test the pressure of a well when you drill an in-fill well?

A. Yes, sir.

Q. What are those wells coming in at, generally?

A. In the center of the Blanco-Mesaverde reservoir it may vary anywhere from 4- to 700 pounds bottom-hole pressure. As you move out into the edges the pressure increases, because it's a much tighter reservoir.

Q. Do you think that the vertical wells that are currently within your proration units would ultimately drain the gas in place in that proration unit? It may take 50 years to do so, but would ultimately get that gas?

A. I do not. I feel like we need to intersect additional sand lenses that exist in the proration units today.

Q. You don't feel that a diagonal well would do more to increase your deliverability and not your reserves? You feel it would also increase the recoverable reserves?

A. We're hoping to under that proration unit, yes, sir.

CHAIRMAN LEMAY: I have no further questions. Thank you. Additional questions? The witness may be excused.

MR. KELLAHIN: Mr. Chairman, I have an additional witness to call at this time. He has not been previously sworn. I would like to call the president and chief executive officer of Meridian Oil, Inc., Mr. Don Clayton.

CHAIRMAN LEMAY: We're very happy to have Mr. Clayton in Santa Fe.

DONALD W. CLAYTON

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

EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Clayton, for the record, sir, would you please state your name and occupation?

A. Donald W. Clayton. I'm CEO and president of Meridian Oil.

Q. Mr. Clayton, will you give us some of your professional background and employment history in a summary fashion?

A. I have a B.S. degree in petroleum engineering; I'm a registered professional engineer. I have drilled all over the world and produced all over the world, and I consider expertise not only in drilling and producing, but engineering, geology and geophysics and petrophysical analysis.

Q. How long have you been the chief executive officer of your company?

A. For a little over two years.

Q. During the course of your employment in that capacity, have you been involved with production on behalf of your company in San Juan Basin, New Mexico.

A. Yes, I have.

Q. Why have you taken the opportunity to come and appear before this Commission today, Mr. Clayton?

A. Mr. Chairman, Commissioners, I think that the outcome of this hearing is important to Meridian Oil. I think it's important to the oil and gas industry in the State of New Mexico, and I think it's important to the State of New Mexico.

In 1986, the State of New Mexico's annual gas production had gone down to 692 Bcf or about 1.89 Bcf per day. In 1989, the production was back up to 830 Bcf, or approximately 2.3 Bcf per day. The result of that dramatic turn-around in produced gas volumes in the State of New Mexico is the result of new technology brought to the San Juan Basin in the State of New Mexico.

I'm here today on behalf of Meridian Oil to bring additional new technology to the San Juan Basin and to the State of New Mexico. Let me state that Meridian's objective is the same objective that the State of New Mexico has, and that's to efficiently manage the development and production of hydrocarbons.

Specifically in the Mesaverde gas reservoir, there has been 7.8 trillion cubic feet of gas produced. What we are here today to ask this Commission to consider is giving us a favorable variance to the proration rules based on economic justification that's been presented on two wells. There have been over 19,000 completions in the San Juan Basin. We ask for the luxury of an exception to the rules on two wells out of 19,000 that have historically been completed. I think that is fair and reasonable.

Let me tell you the larger perspective that I see in either proving or disproving this technology. It's my personal opinion and testimony, as a professional registered engineer, CEO and president of Meridian Oil, that this technology of highly-deviated gas wells and/or lateral drilling technology, will increase the ultimate recovery in the Mesaverde gas formation up to 15 percent, or approximately two trillion cubic feet of additional gas reserves will be recovered out of the Mesaverde if this technology is successful.

We've heard a lot of testimony here today. I'm going to break it down into two simple things. The highly-deviated gas well in the Mesaverde formation will allow you an increased sweep efficiency of about 10 percent. And that can be demonstrated with follow-up documents, should you like to have it.

In addition to that, the San Juan Basin is 7,500 square miles. Geology and subsurface engineering, geophysics and petrophysics is not an exact science. When mother nature laid down those formations, she had some areas that had high permeability, some that had low permeability, some that had no permeability, and some that had micro fractures and larger fractures. The second part, in addition to the sweep efficiency, is that drilling the highly-deviated gas well in the Mesaverde will let you intersect micro fractures and other fracture systems that have not been penetrated by the traditional vertical well and have not been fractured into by the wellbore stimulation techniques as we know in 1990.

Those two reasons are the reasons that I believe that this new technology has that topside potential. Let me go one step further and tell you, when this technology is developed and applied, it will not be limited to the Mesaverde formation. It will also be applied to Picture Cliff in the Dakota Formation. Again, I think as a registered professional engineer, in my opinion you could expect an increased sweep efficiency and penetrating fractures not penetrated by vertical wells where you will increase your ultimate recovery from those traditional formations up to 15 percent. Or a total now, from all traditional zones in the San Juan Basin, of about five trillion cubic feet of reserves that would not be recovered under current state of the art expertise.

Let me break that down into a dollar figure. The Mesaverde alone, with approximately two additional trillion cubic feet, if recovered, would generate incremental income to the State of New Mexico of approximately $300 million. If the technology were successful and applied to all formations and you got up to the five trillion cubic feet of ultimate recovery, then you would be looking at incremental revenue to the State of New Mexico in excess of one-half a billion dollars, and that's why I'm here today.

Let me go ahead and share with you what's going on in the State of North Dakota, the Williston Basin. They're currently relaxing the procedures to allow you to get permitted with high-angle wells or lateral technology wells, and they're also rewriting the guidelines for these type wells.

In addition to that, the State of North Dakota has reduced the severance tax on these specific wells with this technology, from 12 percent to 5 percent. They did that fully realizing that that would probably be a loss of income to the state. What's happened is, the State of North Dakota didn't lose revenue, their severance tax went up one billion dollars for Meridian alone.

If you move into your sister State of Texas, you'll see that one high-angle well or laterally drilled well is given an oil allowable of four times a vertical well. Those rules are currently being relaxed and in this morning's paper they have an article stating that they plan to rewrite the rules governing high-angle wells or lateral wells in the State of Texas.

Let me go ahead and talk about this technology. High-angle gas wells and/or lateral drilled wells, it's my personal opinion that when Meridian develops and applies this technology, that all producers in the State of New Mexico will benefit from the work that Meridian and others, such as Amoco, ARCO, Conoco, or any who elect to develop this technology, that they will share in the benefits of this technology very similar to the way that they're now currently sharing in the coal seam degasification project that was brought to the San Juan Basin. That technology is not limited to Amoco and it's not limited to Meridian, and I think you've seen a dramatic turn-around in gas volumes.

I'm here today to tell you that, in my perspective, I feel very positive about the technology discussed today, what it can do for Meridian, what it can do for the oil and gas industry in the State of New Mexico, and what it can do for all the people of the State of New Mexico in incremental revenue that would be left behind if these wells were not allowed to be drilled. Thank you very much for taking the time to hear me.

Q. Mr. Clayton, let me ask you a follow-up question to your comments. Will you authorize the drilling of the two pilot project wells for the State of New Mexico under the current Examiner Order?

A. We have an investment, a high-risk investment in the State of New Mexico in the hundreds of millions of dollars on coal seam degasification, where we took all that risk up front. I feel very good about this type of technology, but Meridian, as the ninth largest gas producer based on domestic reserves, has other projects in the United States. What well do is simply apply the prioritization by discounted profit to discounted investment, and pick the wells that we drill because we have an obligation to the shareholder.

Meridian currently, right now, only has about a four-and-a-half-percent return on net assets. From all the hundreds of millions of dollars we've invested throughout the United States, a four-and-a-half-percent return is not adequate to the shareholders, so we have an obligation to invest our money from this point in time forward in the wells that are economically attractive.

In answer to your question, the wells, without the two times that some of our people have talked about in the equation, will simply compete on a discounted profit to discounted investment prioritization, and in all likelihood they will not get drilled.

MR. KELLAHIN: Thank you, Mr. Chairman.

CHAIRMAN LEMAY: Mr. Kellahin, Mr. Lund.

EXAMINATION

BY MR. LUND:

Q. Mr. Clayton, I think you testified that you want a favorable variance to the proration rules for two wells out of 19,000?

A. I testified to the favorable exception to the current rules on two wells. I doubt very seriously if two wells is a significant threat to any of the producers in a Basin 7,500 square miles, as far as taking an unfair drainage situation. And after the two wells, we'll look at the results jointly and decide with this Commission and with the industry where we go at that time.

Q. You're familiar, aren't you, Mr. Clayton, with the duty of a lessee to protect their lease against drainage, aren't you?

A. Yes, I am.

Q. And that applies to each lease on an individual basis, not on a big picture basis, doesn't it?

A. I think that Meridian has an obligation to its royalty holders. If we're going to leave, as an industry, two trillion cubic feet behind in the Mesaverde because we need to make some rule changes, then I don't think as CEO and president of Meridian, I'm doing my job.

I think until that expertise is developed and used and widely accepted by all the industry, there will be some discrepancies. But I think the biggest discrepancy would be to take a landowner's land and not do the things as a prudent operator you need to do, and leave two trillion cubic feet behind in the Mesaverde and leave three additional trillion cubic feet behind in the Picture Cliff in Dakota, when this Basin is going to been running short of energy in the year 2000 and beyond. That's where the bigger obligation lies, and that's where the bigger picture scenario comes in.

Q. I don't think we dispute your bigger picture, sir. My question was, isn't it true that as a legal obligation we have to protect each lease against drainage, not just looking at the big picture?

MR. KELLAHIN: Object to the question. He's framed it in context of a legal obligation, and this witness is not qualified as a lawyer to render a legal opinion.

MR. LUND: That's a good point. I withdraw the question. I didn't mean to state it that way.

Q. Based on your understanding of the oil and gas business, and you've got considerable experience, isn't is it fair to say that each lease must be protected from drainage?

A. When Meridian takes a leasehold, as a prudent operator we do everything that we can to go ahead and see to it that our leaseholder and Meridian is protected from drainage. But that is no excuse to be inefficient and go through, like some of the industry did the last 30 years, and not be as efficient with the State's natural resources or the royalty holder's resources and not develop that property in a prudent and efficient manner.

Q. I think you stated that if this technology works, you expect an increase of 15 percent in ultimate recovery from this pool?

A. The statement was, up to 15 percent. That would approximately be 10 percent due to the increased sweep efficiency, which I'll be very pleased to draw up on a chalkboard, if you would like to see it, and then up to 5 percent increase from micro fractures and larger fractures not penetrated by traditionally vertically drilled wells and/or well stimulation, such as fracturing, that go in an uncontrolled direction, that may be adverse to what the fractures are.

Q. I take it you've done a study that leads you to those two conclusions?

A. That's not necessarily a study. I've witnessed that. I've witnessed it in drilling 33 lateral wells in the Williston Basin in North Dakota and some 47 high-angle or lateral wells across the United States.

Q. That's in some sort of report or some sort of--

A. It's in the same form as it is at Amoco. It's in the form of proprietary information.

Q. But you're not suggesting you want to disclose that to the Commission?

A. I would be glad to show the general principle, if you would like to see it.

Q. Yes, sir, I would.

A. May I have a chalkboard?

A. If the Commission would excuse a non-draft person, if this were 160 and 160, and you drilled two vertical wells, the experts have testified to a radius of drainage in the two vertical wells as such. Now, if you can picture drilling down and horizontal through these points, and let's say this is where your well went down vertical, and you drilled horizontal and, you have this same radius of drainage that earlier experts have testified, then your drainage area is going to come across as a rectangle. And the shaded area here, geometrically, is an area of the reservoir that will not be swept and have the sweep efficiency of the radius drained by two vertical wells. When you calculate that out, you come out with approximately a plus 10 percent additional sweep efficiency that would not get drained under uniform homogeneous permeability of a reservoir.

I'm saying you'll get up to 10 percent for increased sweep efficiency. And then, it's my personal opinion, if you have a vertical well here and you have a vertical well here and you have a pooling or a fracturing in this area, in this area, in this area, in this area and some of them running through the well, and these fractures are not hooked up, when you drill down and vertical you'll intersect all fractures. In fact, it's almost theoretically impossible to miss them, because mother nature did not lay them down parallel to each other, and it's highly unlikely that you have the technology to drill a straight, parallel well with fractures, so you're going to pick up the gas in the porosity of the micro fractures and fractures larger than micro fractures, and that's where you'll get up to an additional 5 percent. Any questions?

Q. I take it you agree with Mr. Dunn, I think his analogy was a vertical stack of pennies, and if you lay it down it will get that increased area?
A. I agree with what I just explained.
Q. You don't agree with Mr. Dunn's analogy?
A. I don't disagree with Mr. Dunn, but a stack of pennies, I think, was an attempt to try to convey something very technical to a legal mind, that would understand what I just explained.
Q. We certainly need all the help we can get; as Mr. LeMay always says, lawyers are incompetent.
Is it your opinion that the drainage from that deviated wellbore would not cross over into the offsetting 160's?
A. On a individual case-by-case, I have no way of knowing whether it it will or it won't, and nobody else does either.
Q. You have to look at what the production is before you can make that determination?
A. You can't even make that determination after you get a P/Z. Can you look down below the ground in excess of one mile and tell me how far and in what directions mother nature put the main fracture system, let alone the offset azimuth of the micro fractures coming off the main fracture system? It's

highly unlikely.

Q. All I'm asking you is, can you determine what the drainage radius is going to be of a deviated wellbore in the absence of production data?

A. There are engineering calculations. It's not an exact science.

Q. Would the drainage radius be larger if the well is extremely productive and it does intersect these micro fractures that you've been discussing?

A. I'll refer back to earlier expert testimony. It's not predicated on any one parameter but many variables, such as porosity, permeability. Is it a uniform sandstone with no fractures? does the sandstone have micro fractures? micro fractures and larger fractures? The question is too general.

Q. You're not testifying that the deviated wellbore would never drain beyond the 160, are you, or the 320?

A. In what example?

Q. Well, you're laying out all these factors.

A. This is a hypothetical example. I'm sure that you're aware, as an attorney, that you have well spaces down to two acres in size and you have some that are in excess of 2,000 acres. A lot depends on where the drilling is and what the characteristics of the reservoirs are. I can tell you, in 7,500 square miles in the San Juan Basin that you're going to have to look at that on an individual, geographic-by-geographic area, to determine whether 160 is proper, 320 or 40 or whatever. You can't make any general assumptions to cover the San Juan Basin in the Mesaverde and Dakota. It's too big.

Q. So you can say, too, you can't make a general assumption that this deviated wellbore would not drain beyond a 320, either?

MR. KELLAHIN: Mr. Chairman, that question has been asked and answered twice now, already. I don't know how else the witness can answer it.

MR. LUND: I think I'm entitled to a response to that, Mr. Chairman.

MR. KELLAHIN: He would be answer the same question.

CHAIRMAN LEMAY: Just rephrase the question and I'll make a ruling. What were you asking, Mr. Lund?

Q. Mr. Clayton, all I'm asking--

MR. KELLAHIN: Excuse me.

MR. LUND: Excuse me. Let me ask the question.

MR. KELLAHIN: You've already asked the

question. I've objected. And the basis for the objection is that Mr. Clayton has said that none of the engineers in this room can tell you if there's going to be drainage or not in the Mesaverde, and now he wants to ask him the same question again.

CHAIRMAN LEMAY: Is that your question?

MR. LUND: I think that mischaracterizes the point.

CHAIRMAN LEMAY: I want to hear the question again, if it's the same as Mr. Kellahin says has been answered. If it's a different question, then maybe the witness can respond.

Q. (BY MR. LUND) I think you testified, and correct me if I'm wrong, sir, that you can't tell what this drainage radius is going to be on this deviated wellbore because you need a whole bunch of additional information?

A. I think within the limits of the technical expertise of the technical group that does reservoir engineering, whether it be at Amoco, Meridian, Exxon or anyplace else, that they can give a very scientific best guess based on accepted formula in all the many parameters that reservoirs have. Now, if you're asking me about a specific well in the San Juan Basin, whether it will or it won't drain more than this radius, I'll defer that to the technical people we have working that specific area.

Q. All I'm asking you, depending on those variables that you mentioned, this deviated wellbore could drain less or greater than a 320, isn't that right?

A. Yes.

Q. Would Meridian still drill these two deviated wellbores if it did not get the two times deliverability factor?

A. I think I've answered that question. Those two wells, without what we've asked for, will have to compete on a discounted P over a discounted I basis with the other projects we have across the United States. I don't want to waste the Commission's time or my time answering the same question more than once.

Q. So your answer is no?

A. My answer is what I said.

CHAIRMAN LEMAY: Mr. Lund, we don't want to characterize the witness's answer. I think it was a conditional response, as I heard it, not yes or no but it would have to depend on upon these other variables.

MR. LUND: Mr. Chairman, I don't mean to be argumentative. I'm just trying to understand what the witness testified to.

CHAIRMAN LEMAY: Yes, I understand that.

MR. LUND: Thank you.

CHAIRMAN LEMAY: Thank you. Additional questions of the witness? Commission Weiss?

MR. WEISS: Yes.

EXAMINATION

BY MR. WEISS:

Q. What has been Meridian's experience and yours, when you go to the Commissions in other states and request this type of an allowable?

A. To be quite candid with you, the State of North Dakota at one time ran in excess of 30 rigs and they were down to two rigs running, both Meridian. They came to us, when we elected to move back into fractured fractured Bakken shale, and said, "What can we, as the State of North Dakota, do to get you people to bring your technology up to the wellbore in North Dakota, get it out of the research labs and drill a well?"

And we asked at that time, the first horizontal well we drilled in the State of North Dakota, we had a section 640 acres. We had a vertical well here that we wanted to prove up that drilling technology the one time. We were going to go ahead and spud the well somewhere in this area, to the proper spacing away from the lease line.

What the State of North Dakota said, "Here's your permit, guys. If you need anything else, let us know." They went ahead and took the conventional, accepted radius of drainage for the vertical, they backed this off, the state requirement on spacing. This was our permit edge. They said, "We wish you well. Keep your bit inside that area, and you can produce the well at whatever it will make. We wish you well getting it down."

What we did is, we drilled down vertical. The current world record at that time was about 1,500 feet lateral for a medium-radius horizontal, and we went from through vertical to through horizontal in 600 feet, and we drilled a well up like that 2603 feet at 86 degrees or higher. The well came in in an area that was considered to be noneconomic by the industry because they had moved out. It came in at 300 barrels a day. That was over two years ago. The well is currently flowing on its own energy source with no pumping or hydraulic lift, and is currently producing about 250 barrels a day. That well has produced in excess of 240,000 barrels and has an ultimate recovery of around 600,000 barrels now.

The typical vertical in the Bakken would give you about 40 barrels a day, with an ultimate recovery of somewhere in the 40- to 60,000 barrel range. The State of North Dakota came back, said, "What else can we do to get you to continue to drill these types of wells in the State of North Dakota?" We did not ask for the reduction in severance tax from 12 to 5 percent that covers the first 18 months of production, but they gave it to us anyway because they wanted to see us up there.

We have approximately in excess of 5,000 barrels a day coming out of fractured Bakken shale that the industry several years ago determined to be uneconomic. What we're asking to do in the State of New Mexico is to come in and drill two highly-deviated gas wells. We're asking for a very marginal, in my opinion, variance, to allow us to know what the economic numbers are going to be, and then we'll take the mechanical risk, we'll take the risk of not getting the increased sweep efficiency we talked about, and we'll take the risk on not hitting the micro fracture systems that haven't been penetrated by vertical drilling or wellbore stimulation. At the ends of the two wells we'll come back to the Commission and show you the data.

The thing that I guess has been the most eye-opening to me today, is that some of the comments I've heard have been, "Well, my God, what if you're successful. If you're successful your allowable is going to be too big." At Meridian Oil we want to plan for success. We want to go get that five trillion cubic feet. If it means you have to change some rules that were written 30 years ago, we don't want to dictate what the changes would be, but we want to be a part of it to bring that new technology to the State of New Mexico.

I can assure you Amoco is a good competitor. Amoco is a very, very good oil and gas operator, and if we drill a highly-deviated gas well and we get a 16 million a day well, they're going to come and offset it. Make no mistake about it. And they'll be coming right back to the Commission and saying, "You know, that isn't such a bad idea. Give us the same deal on two wells that you gave Meridian."

And it's not going to be long after that, just as in the coal degasification, that the smaller independents say it can't be that tough to do, and we're either going to join the big boys until we learn the technology, or we're going to go it alone. Right now you can't pick up a lease in the San Juan Basin that have coal underneath it, because Wallstreet, the drugists, the dentists and everybody else is in here to get a piece of the action.

I'm telling you, this is a new, different type of technology that has tremendous upside potential. And to put it in perspective one more time, we're asking for a variance on two wells when there has been 19,000 completions already. Was that a long-winded answer to your question?

Q. I heard what you said. They didn't give you an increase in the allowable, though, did they?

A. The State of Texas will give you four times a vertical well now in the Austin Chalk. A vertical well drilled to that depth will get somewhere about 300 barrels per day on 80-acre spacing. They allow OREX, not Meridian, but OREX, to go ahead and replace four 80-acre spacing wells with one horizontal. And the current allowable is 1312 barrels per day on the one horizontal wellbore.

The State of North Dakota says produce it at a maximum efficient rate, you determine what that is. If somebody feels like they're being drained, they have the obligation, as a prudent operator, to go in and put a well down and offset that well, very similar to what the industry has done in the last 40 years on offsetting the vertical wells.

Q. Do you think the fact that that's oil and this is gas enters into it?

A. No, not at all.

Q. Markets don't--

A. No. Excuse my English, but if you go back to Darcy's equation and you look at the mechanical advantage you get, you should get flow volumes of 7 or 8 times out of the horizontal or high-angle, relative to a vertical. But, in reality, we're finding out you're probably in the 3 to 4 range. So, I don't think the thing is going to get out of hand.

I think on two wells that the type of arrangement that was suggested by our technical people today is very reasonable, because they're willing to cap that, you know, at the values discussed. And we're not going to drill 600 wells like we've done in the coal seam. We're going to drill two wells and come back to the Commission. So the risk of being successful, in my opinion, is not that much of a threat to the other producers.

Q. Would you share the information from these two wells with the public?

A. We'll follow the same course and procedure we did on coal seam degasification. We think if we're going to take the risk up-front, mechanically and financially, that we should have a certain amount of time to fine-tune that technology. But it's my opinion that in 18 to 24 months everybody can follow suit, if they should so desire.

I think that's what we've demonstrated in coal degasification. You have people running the preperforated liners, you have them creating the pressure sinks. The best example would probably be Blackwood & Nichols and a couple of the smaller independents that have moved in, and they have the benefit of the hundreds of million dollars that we've invested to prove this project up to industry.

The California customers said it won't work. You had other majors that said it wouldn't work. Our respected Amoco over there said that our technology would only give you short-term volumes and it wouldn't last over a period of time. I think now that our competitor is taking a look at their technology and ours, and I think they'll be doing some of both in the future.

So there's no way that one independent--and that's what we are--there's no way that one independent is going to have a captive grasp of this new technology we're trying to bring to the San Juan Basin. There's no way we could hold that tight.

Q. You don't publish it as such, do you?

A. No. We've been on the cover of The Petroleum Engineer, World Oil, The Oil & Gas Daily Investor, and other publications with our data on horizontal drilling, and with our data on coal degasification.

MR. WEISS: Thank you.

EXAMINATION

BY CHAIRMAN LEMAY:

Q. Mr. Clayton, in the Williston, they put the Bakken horizontal in 640's up there, didn't they?

A. They have just recently changed those rules. We're drilling on 320's. The industry went up there and leased up a lot of land without intending to drill, and they wanted to drill one well on 640's not to get the rigs running but to hold the acreage until they could cut a deal.

The State of North Dakota, on December 19, 1989, changed the rules to read that you're allowed to drill up to four wells on a 640. What they're saying, if you want to drill one, go drill one. If there's another operator that thinks the maximum efficient drainage pattern is 160, he can drill four.

Q. There are no allowables in the State of North Dakota, are there?

A. No, sir. You have some restriction on the gas that's allowed to be flared, so there is a delay until you get your pipeline, but it's temporary restriction until you can sell that natural gas.

Q. On the vertical hold, was the Bakken in 40's before you came into the horizontal--

A. It's my understanding that they had some drilled on less than 40's. You either hit the fractures or you didn't. If you hit the fracture you made a well. If you didn't, you had a dry hole. And, consequently, when you did full-cycle economics on 10 wells, 20 wells drilled, you were losing money until this technology was proven.

CHAIRMAN LEMAY: That's all the questions I have, thank you.

THE WITNESS: Thank you very much.

MR. KELLAHIN: Mr. Chairman, that concludes our presentation.

CHAIRMAN LEMAY: Thank you, Mr. Kellahin. Do you have any witnesses, Mr. Lund?

MR. LUND: I think you indicated earlier you would like to hear some of the production data and things like that, and we're prepared to present that for you.

CHAIRMAN LEMAY: I'll take a break for lunch, if you are. I suggested that it would help the Commission if you're posing the application that we have some alternative recommendation. That was all.

MR. LUND: We do. And we do have an alternative recommendation.

CHAIRMAN LEMAY: Okay. Well, let's take a break and we'll reconvene at 1:30.

(Thereupon, the noon recess was taken.)

CHAIRMAN LEMAY: Shall we convene? I take it you're through with your case, Mr. Kellahin?

MR. KELLAHIN: Yes, Mr. Chairman.

CHAIRMAN LEMAY: Amoco's case, Mr. Lund?

MR. LUND: We have one witness, and he's previously been sworn.

Mr. Emmons, would you take the stand?

LARRY N. EMMONS,

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

EXAMINATION

BY MR. LUND:

Q. Mr. Emmons, would you please state your name and your business address.

A. Larry N. Emmons, and business address is

P.O. Box 800, Denver, Colorado, 80201.

Q. By whom are you employed and in what capacity?

A. I'm employed by Amoco Production Company as a petroleum engineer.

Q. You've never testified as an expert before the OCD or the Oil Conservation Commission, have you?

A. No, I have not.

Q. Briefly then, what is your education from college on?

A. I graduated from Purdue University in 1979 with a Bachelor of Science in Chemical Engineering.

Did you want me to go into my work experience after that?

Q. If you would, please. Since your graduation from Purdue, what is your relevant work experience?

A. I started with Amoco in 1979 in Farmington, New Mexico, where I worked approximately 18 months, drilling a number of wells and hydraulically fracturing a number of wells and participated with our research center in developing a hydraulic fracturing technique.

Then I went to our Denver office where I worked Oklahoma production from our division office.

I then went as an engineering supervisor to Evanston, Wyoming, and worked the Overthrust area. Then to Oklahoma as a regulatory engineer where I testified approximately 200 times in front of the Oklahoma Corporation Commission.

I then came back to Denver, continued in Oklahoma, as well as testified approximately 40 times in Kansas. And my current responsibility includes Arizona, California, New Mexico, and Kansas.

Q. You're a Professional Engineer?

A. Yes. I'm registered in the State of Oklahoma, and I took the test in the discipline of petroleum.

Q. You're not the President and Chief Executive Officer of Amoco Corp, are you?

A. I'm not currently nor have I ever been. I do aspire to be so.

Q. Before we talk about specific points, would you please give us a summary of what Amoco's position is in this case?

A. Amoco is not opposed to the drilling of a horizontal well; in fact, we're looking -- I think it's called a deviated well in this case. In fact, we're looking at doing the same thing. Where our concern is is correlative rights. We're obviously the operator of some offset units. We're concerned about the main dispute here, being the doubling of the allowable or doubling of the deliverability to set the allowable could adversely impact the offsets, as well as impact the balance of the pool.

We do have what we feel is a fair alternate proposal. Realizing that the deviated well is in fact encountering both quarter sections, it may actually have the withdrawal and perform like two vertical wells, since it has up to three to four times the contact area. We just don't know what kind of rate will come out of it, but chances are it's going to be significantly higher than a vertical well. There's that possibility. However, we don't feel it's necessary to be as restrictive as what the original order imparted on Meridian, whereby they can only use the deviated well or the two vertical wells.

We feel it would be fair to go somewhere in between; that being using any two of the three wells in the unit, provided the horizontal well did encounter the Mesaverde formation in both quarter sections. Obviously, if they have problems with the well, and it's only in one quarter section, then it should be treated as a standard vertical well. As long as it is underneath, encountering the Mesaverde in both quarter sections, we don't care which of the three wells they use to determine the allowable. They can take the best two.

Q. Let's turn to some specific points about the testimony. First, let's talk about production data from offset proration units to the two proration units we've been discussing. If you would, please, just kind of give it in summary form. If Mr. Kellahin or others want some additional details, you can supply that later.

Let's talk first about current deliverability.

A. I took the February 90 OCD books on the Mesaverde formation and looked at current deliverabilities, which is different from what was presented in, I believe, Exhibit 3.

I believe Exhibit 3, if they had the latest test, they used it. If they didn't, they used what was the previous test. I don't think that's fair in that you're really kind of comparing apples with apples because the offsets that they didn't have data for may have also had their deliverability dropped.

What I determined is that if you look at the -- specifically, on the Howell section and compare that to the offsets, the highest unit deliverability in and around the Howell unit is 2,073 Mcfd, whereas the minimum is 386 Mcfd, while the Howell "E" itself, using the same vintage of data, was 773 Mcfd. So it was by no means the poorest unit, but it wasn't the best unit either.

However, if deliverability is the problem, drilling another vertical well could alleviate that problem because the vertical well may have a higher deliverability, and therefore improve the deliverability out of the unit.

Q. Mr. Emmons, I think maybe the Meridian witness testified that the deliverability for the Howell "E" was lower. What do you have have to say about that?

A. I believe he testified it was 531, yet that was because -- and I don't have Exhibit 3 in front of me, but I believe on the Howell E 2, he had something less than around 150 Mcfd range. He had -- in November 1990 deliverability books, it shows that should actually be 428 Mcfd.

Q. Let's talk about the current deliverability in the Riddle section and the offsets.

A. The Riddle section, the offset units had a maximum rate or maximum unit deliverability of 2,612 Mcfd, a minimum rate which was 176 Mcfd, while the

Riddle itself had a deliverability of 741. And I don't believe there's an exhibit showing that, but what it shows there is, again, the Riddle section is not the poorest unit in the area, nor is it the best. Again, they can alleviate those problems by drilling another vertical well and therefore getting a higher deliverability.

Q. Let's talk for a little bit about cumulative production data. Would you please give us a summary of what your conclusions are about that in these particular proration units.

A. Without going into a lot of detail on the production -- I can, if that's desired, but, in general, if you look at the Howell unit and look at the production of the Howell unit compared to the surrounding offsetting units, their production to date has been approximately 150 percent above or 150 percent of the production of the average of the offsets. That being if you took the production of all the offsets and got an average for them, the Howell unit is actually doing about 50 percent better.

Q. What about the Riddle unit?

A. The Riddle unit, unfortunately, I didn't bring all the data with me, but I looked at the units that were to the east and to the west, as well as to the south, and that came up with the Riddle unit producing at 130 percent of the average.

Q. So based on your analysis of the current deliverability data and the cumulative production data, do you think that the two units that Meridian has been discussing are suffering under any kind of competitive disadvantage?

A. I don't believe so.

Q. Let's talk a little bit about the two times deliverability factor that has been introduced by Meridian. Do you have an opinion as to whether that two times deliverability factor would protect the offset owners' correlative rights?

A. Yes, I do. I feel that the deliverability factor is a special exception that does not protect the offset unit's correlative rights for a variety of reasons. Basically, that special exception is not given to any other unit or any other well within the Blanco-Mesaverde field.

By taking only a single well and doubling that, you've taken out an implied limitation in the proration formula. If you get a tremendous well in one quarter section, you're forced to put that width -- your well in the other quarter section which may not have similar permeability, porosity, or production characteristics. So you're not able to take your best well and double it. You're forced to average it down by incorporating one of the four wells.

Also, I expect that the deviated well will have a higher deliverability because it has quite a bit more formation contact. The entire purpose of the deviated well is to have a better opportunity to hit permeable sands, and if they do so, you would expect a higher deliverability.

For the offset operators, there's the thought that the offset operators have the same ability to protect themselves by drilling horizontal wells. Unfortunately, that forces the offset operators to abide by someone else's economics. It forces us to drill a horizontal well or a deviated well, which is more expensive, when in fact a vertical well may accomplish the same goal, but in order to get the allowable exception, we would be forced into drilling a deviated well.

Q. Let's talk a little bit about Meridian's suggestion that a production cap be placed on deliverability for the deviated wellbore. Do you have an opinion as to whether that is fair and protects Amoco's correlative rights?

A. The cap is based on the highest

deliverability in the entire pool. Obviously, that doesn't have anything to do with the surrounding units. The surrounding units don't have anywhere near the capability -- the immediate surrounding units don't have anywhere near the capability of what the highest units in the pool make.

Also, they're using the -- I think, to demonstrate that, I believe they mentioned they're using the Amoco's Fields LS2A, which is in Section 25, 32 North, 11 West, which is two to three townships away from this area; so I don't feel that's a fair comparison.

One thing I'd like to add, these units do, even though they may have initially a high rate, they do fall. The current 1990 test on the Fields 2A that's been recently filed with the Conservation Division has a unit deliverability of 2,870 Mcfd; so a significant drop in it.

We don't know whether retest will increase that rate or not, but that shows you the kind of variation you can have in a unit. But what Meridian's cap does, it says, if you have that kind of drop on that unit, they want to switch to a different unit. The proration formula has its natural protection mechanism in, whereas if you have an extremely good unit that produces a lot of gas, its pressure should drop; therefore, deliverability should drop; and, therefore, it drops down and helps protect the offset unit. But with this cap, they want to switch to a different unit that may not have had the same drawdown.

Q. So Meridian is not willing to live with the natural production decline in this particular field?

A. Not based on the cap.

MR. LUND: Mr. Chairman, it just occurred to me, I may not have asked to qualify Mr. Emmons as an expert petroleum engineer.

CHAIRMAN LEMAY: His qualifications are acceptable.

MR. LUND: Thank you. I apologize.

Q. Let's talk about some miscellaneous points. You and I discussed the testimony, and we would like to make a few more points.

Let's talk first about the fracturing of wells. I think Commissioner Weiss asked about fracturing wells in this area, and whether they get any special treatment in terms of a special allowable or anything like that. Based on your study, what's your opinion about that?

A. No. To my knowledge, even though great dollars are spent on hydraulically fracturing wells, especially when the technology was new -- I was working the San Juan Basin when we were doing that. I participated at the research center. We did many fracs where we had expensive gauges. We had a lot of time spent on an individual well just to build the data. So we spent a lot of dollars; yet I don't believe any special allowable exceptions were made on those wells.

Q. What about economics? There was some testimony this morning from the Meridian witnesses about their economics. What's your opinion about their economics vis-a-vis other producers in the area?

A. The problem I have with the economics, obviously, they want a special exception to the allowables to make it a profitable venture. Unfortunately, that doesn't necessarily tie to the correlative rights of the offsets.

As a matter of fact, as I look at their economics, I think they made a pretty good case that they should be drilling vertical wells instead of horizontal wells. It shows they really have to have a tremendous rate on the well in order to make a deviated well pay out. Maybe they can accomplish the same results by drilling vertical wells.

Q. There were some other questions this morning I think from Chairman LeMay and from Commissioner Weiss about whether these deviated wellbores would hit virgin pressure areas or pressure-depleted areas. What's your opinion on those particular issues?

A. There's always that possibility. It's a heterogeneous reservoir. So I agree that there is that chance, and that's the whole reason we're concerned about the double allowable. However, one of the exhibits that was presented on the Scott P/Z curve, it was stated they drilled a replacement well right next to their original well, and it came in at the same pressure. That shows to me that they aren't generating new reserves. Granted, they did get reserves faster, but they weren't new reserves. They were reserves that were probably going to be recovered by an offset well because it's been pressure depleted.

Q. Mr. Emmons, there was also some testimony, I believe, from Mr. Jones about the proration formula and when wells get shut in. That appears to be an issue in this hearing. What's your opinion about the offsets having to live with those proration rules vis-a-vis Meridian's proposal in this case?

A. If you look at Exhibit 13, I believe that will apply to any well, the proration formula. If they drilled a vertical well, they would have the same limitations. That is part of the proration formula, and that's part of the protection of the proration formula. They're asking for a deviation from that to pay out their well, and I don't feel that's protecting correlative rights.

Q. There was also some discussion about oil wells versus gas wells and drainage and things like that. What are your thoughts about that particular issue in the hearing?

A. I don't feel comfortable in making general comparisons between gas and oil. I feel you have different market considerations, different production mechanisms. The Conservation Division even treats them differently. You've got a prorated Mesaverde field. It's not fair to compare it to an unprorated oil pool. Your drainage patterns are different. Spacing unit sizes are different. So I don't think a general comparison is fair.

Q. Let's talk next about Mr. Clayton's diagram. We had it up on the board, but maybe you could step to the board and redraw it. It seems to be missing. I know you had a few thoughts about that. Would you go ahead and do that?

A. I'm not a draftsman either; so I'll just do my best.

Q. You'll have to describe orally as you go because the court reporter won't have that in front of her.

A. Okay. I'm simply trying to recreate Mr. Clayton's exhibit, which is a representation of a section divided into quarter sections. Even though this specific case deals with stand-up units, this picture deals with a lay-down unit in the south half.

He drilled a wellbore in the center of each quarter section in the south half, representing two vertical wells. If I remember correctly, he drilled a vertical well that started up in the north and then intersected both vertical wells by continuing from the west half into the east half.

He then drew a circle around each vertical well, and this is supposed to be a circle (indicating), representing a drainage pattern that incorporated most of the section -- most of each quarter section that would be observed by the vertical wells.

By drilling the deviated well, he then connected by tangent the ends of the drainage pattern of the vertical wells and then shaded in the area, showing that that would be what would be produced by the deviated well that could not be produced by the vertical wells.

Q. That apparently was part of his figure of 15 percent additional ultimate recovery?

A. Right. I believe he attributed 10 percent due to that. That doesn't directly apply here because the Mesaverde is segregated, and, actually, they're only going to get, I believe, in one portion of it, the Cliff House, and another portion, Point Lookout, where that same limitation is placed on vertical wells.

But the key point I'd like to make is that by drilling a horizontal well, there is an implied location exception that they do not have to be 130 feet from the center of the unit boundary. If you take that implied restriction away and drill your third vertical well right in the center, you're going to recover a majority of the reserves that would have been recovered by the horizontal well.

Another thing I'd like to point out, this deals with -- here I'm erasing everything except what's in the -- what would be the drainage pattern in a vertical well in the west half.

Although the deviated well is projected to go into the other quarter section, there is no way they will be able to govern where the permeable zones are. Obviously, for them to get the drainage that they would desire, hopefully, you have a homogeneous reservoir, and you have homogeneous permeability, and therefore it's all going to be produced equally. Unfortunately, the Mesaverde doesn't necessarily do that.

You may actually have one highly permeable zone in the Mesaverde. And that very well could be a single point. You could have an extremely permeable zone. And so the first several years of production out of that well may act as a vertical wellbore. Therefore, it would be unfair to give this unit twice the allowable --

Q. And also if you hit --

A. -- twice the deliverability.

Q. Also if you hit a highly permeable zone in one quarter section, what effect, if any, would that have on its drainage radius?

A. Graphically, instead of having -- if, in fact, this turned out to be the permeable area, if you give it twice the deliverability, then it's going to have twice the drawdown from this area; so your drainage area then goes beyond what was being depicted by the original circle.

So if your vertical well would have recovered the entire quarter section, the horizontal or deviated well could recover from beyond the unit.

Q. If you would, please, just sum up what Amoco's position is and what its proposal is in this case.

A. Amoco is concerned about the correlative right impact by doubling a single deviated well's deliverability and applying that to the allowable. We feel a proper alternative and a better alternative in the interest of protecting the offset's correlative rights would be to allow Meridian to take the two best wells and then have those two best wells determine the allowable for the unit.

We do not care whether they use the horizontal well plus either of the two vertical wells, or if the deviated well turns out to be a poorer well, they would then use the conventional method of taking the two vertical wells. The only restriction I place upon that, again, is the deviated well should encounter Mesaverde formation within both units -- within both quarter sections.

Q. Is it Amoco's intention to discourage or prohibit Meridian's ability to drill these deviated wells?

A. Not at all.

MR. LUND: I have nothing further, Mr. Chairman.

CHAIRMAN LEMAY: Thank you, Mr. Lund.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Chairman.

FURTHER EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Emmons, this case originated before the Examiner in a hearing on September 20, 1989. Are you aware of that?

A. Yes.

Q. You've read the order?

A. I've read the transcript, and I've read portions of the order.

Q. When did you personally become involved in your company's position in this case?

A. Prior to -- well, when we first picked up the case on the docket before the initial hearing.

Q. Am I correct in understanding that your concerns are with regards to correlative rights' issues as they might apply to Amoco's spacing units in the Mesaverde that offset the two project areas?

A. Although obviously I'm here to protect

Amoco's interest, but I'm also concerned about correlative rights in general and the direct offsets.

Q. Within the context of the issues decided before the Commission, they look to the prevention of waste, and they also look to the correlative rights' issues.

A. Correct.

Q. Within that, you have not expressed any opinions or objections with regards to this pilot project preventing waste? Your concern, as I understand it, is the correlative rights impact that this project allowable may have on you as an offset operator?

A. Actually, you can tie it back into waste. If I, as an offset operator, am forced into drilling expensive deviated wells simply to get an allowable relief when I can accomplish the same thing with vertical wells, then it has caused me economic waste. You're protecting correlative rights through a wasteful action.

Q. The prevention of waste concepts that are integrated in the Examiner order are ones that he has predicated on findings that show that the deviated well has got the opportunity to encounter reserves that the two existing wellbores do not encounter. You

don't have any disagreement with that notion, do you?
A. No, sir, but the vertical well may be able to do the same thing.
Q. I guess I'm confused by your position. Amoco is not in opposition to the utilization of the pilot project for highly deviated wellbores, are you?
A. No.
Q. You're not taking the position that we can accomplish the same thing with vertical wells and therefore should not have the opportunity to drill the two pilot wells?
A. Correct. I don't know that anyone knows whether you can accomplish the same thing with a vertical well, but at this time I think a deviated wellbore is a good concept to pursue.
Q. Describe for me the basis by which you are concerned about correlative rights.
A. In what manner? I think I --
Q. In any manner you choose, sir.
A. I think I stated several reasons. I think I just restated one. In order to get a similar allowable relief in the offsets, the offset operator will be forced into drilling horizontal wells. I don't believe that the OCD will grant twice the deliverability on another vertical well.

So you have the economic waste in order to protect against a horizontal well, if it turns out to be a good well.

Q. Your basis assumes that the highly deviated well is going to be more successful in terms of having a higher deliverability than the third vertical well; right?

A. I think that's the whole -- it does, but I think that's the whole reason it's being drilled. I don't think if you were going to get a poorer well, you would drill it.

Q. What if the Commission disagrees with you and decides to offer Meridian twice the deliverability of the highly deviated well and establishes a cap. Now, you and Mr. Lund have talked about the cap.

A. Um-hm.

Q. Do you have a recommendation as to where to place that cap in the event the Commission disagrees with your proposal that we don't use twice the "D"?

A. I can't support that option because I've already explained all the reasons why I don't support the option. I guess I have a problem answering your question because that's not an option that I want to pursue.

Q. I understand it's not. Let's talk about your reasons to object to the cap. You'll concede with me, won't you, that the highest deliverability in the Mesaverde is a well that you operate that's got 16 million a day?

A. I don't believe you'd call it the highest based on the current test.

Q. Let's assume that's approximate, 16 million a day; all right?

A. Okay. That's incorrect, but that's fine.

Q. And that's permitted under the allowable system that we have now?

A. Correct.

Q. We have a deliverability-driven allowable system?

A. Correct.

Q. There are no special limitations on that well even if it was the third well in the spacing unit that had -- this big horse in the reservoir that's got this humongous amount of gas it produces every day; it's not restricted, is it?

A. No. However, its current test is less than 3 million a day. So it's gone from 16 to 3 million, and yet under the proposed cap, then they would switch -- Meridian would then switch to the next best unit. So you aren't comparing apples with apples there.

Q. Let's see if we can find some apples. Do you have a copy of Meridian's exhibit book?

A. I'm afraid I don't.

Q. Let me find one for you. (Indicating.)

Let me have you turn to page 3 of the Meridian exhibit book, Mr. Emmons.

A. Okay.

Q. If you'll look in the lower left-hand corner in Section 22, look at the 86 statewide deliverability on the Howell K 2A well; do you see that?

A. Yes.

Q. 12.4 million a day, is it?

A. Yes.

Q. Look at the offsetting spacing unit that Amoco has, the Florance 45, a little over a million a day?

A. That's correct.

Q. If we're looking for places to peg a cap, here's one within a section of the subject spacing unit, and it shows 12.4 million a day; right?

A. That's the deliverability, yes.

Q. When we look at the advantage that one well enjoys over another in Section 22, there is a significant range of dissimilarities between the two deliverabilities, isn't there?

A. Today. That may not happen tomorrow.

Q. And if this cap is allowed to float, as Mr. Jones proposed, then what you're doing is restricting the allowable rate on the highly deviated well to what actually occurs in the reservoir of this particular pool, don't we?

A. Yes. I have a problem with your term "float." I've already shown you where it should have floated from 16 to 3 million, and you just floated over to 12.4 million. So it's not the same thing as your taking a single unit and abiding by the natural corrective processes within that unit.

Q. Isn't your concern that there's going to be some net uncompensated drainage from the Amoco property to the Meridian because they're going to put this big horse right next to you, and it's going to take your share of the gas? Isn't that what you're trying to worry about?

A. I don't have a problem if Meridian does that and can comply with the current proration formula. Where my problem is is that Meridian is trying to go beyond the proration formula and ask for a special provision to allow a higher allowable. To get to that cap, they're going to have to get 8 million a day out of their well.

I don't see any wells in the immediate offsets units, and when I'm saying "immediate," I mean directly offset units, that come anywhere near 8 million a day in a deliverability out of a single well. And so --

Q. Then you're telling me if we take twice the "D," we're really giving it an artificial allowable that any well in this area can't expect to meet?

A. Let's use an example, Section 22. My answer is possibly.

Look at Section 22. The very example you gave me, it had a rate of 12.4 million a day for its deliverability. Look at the other wells in that same unit that it has to combine with it. It's 413. It's not that -- that well could have come in at 8 million and had the other well in the unit be 413. It would still be limited to 8 million a day. What you're asking for is 16 million a day.

Q. Isn't the underlying concern one where you're worried about the allowable for the highly deviated well enjoying some unfair competitive advantage over Amoco whereby there is net uncompensated drainage from your spacing unit to ours?

MR. LUND: I object to the question as far as net uncompensated drainage. It calls for a legal conclusion. I have no objection to Mr. Emmons testifying about what his understanding of drainage is in general.

CHAIRMAN LEMAY: I'm not sure where you're going, Counselor, on this.

MR. KELLAHIN: Let me rephrase the question.

Q. You're worried, aren't you? Correlative rights means what to you, sir?

A. As Mr. Jones mentioned earlier, the opportunity to produce your fair share of the reservoir.

Q. Without waste?

A. Without waste.

Q. Your share is defined, I presume, by some volume of gas that underlies your spacing unit?

A. Generally, yes.

Q. You have expressed concern over the cums that have been produced within the areas around the Howell well; right?

A. Right.

Q. Can you tell me what percentage of the total gas in place for the spacing unit that that cumulative number represents for any of the spacing units?

A. I would have to share some of the same concerns that the geologist presented; that it is difficult to map the area. Quite often, the four volume numbers and the P/Z numbers do not compare. So to compare it directly to gas in place, Amoco has the same concerns that Meridian has.

Q. I assume then by your answer that you have not attempted to calculate volumetrically the recoverable gas in place either under the Howell unit or any of the other spacing units that might offset that spacing unit?

A. That's correct.

Q. And that's true of the Riddle as well?

A. Correct.

Q. Have you as a reservoir engineer attempted to construct a P/Z versus Q plot on any of the producing wells in this particular area for the Howell or the Riddle?

A. No, I have not.

Q. So based upon that analysis, you can't tell me what you would project to be the ultimate recovery from any of those wells?

A. I have looked at some P/Z analysis for the two units involved.

Q. Can you tell me what portion of the current cumulative production from any of those wells is related to the gas volumes you get from the P/Z analysis?

A. I'm not sure what you're asking me.

Q. You told me you haven't done volumetrics to give us gas in place or recoverable gas for any of the spacing units?

A. Correct.

Q. Have you taken the methodology of looking at P/Z to get you cumulative gas from that particular well?

A. I have looked at the P/Z curves on the wells.

Q. Is the basis of your opposition based upon ultimate recoveries per spacing unit, using the P/Z analysis?

A. I didn't do the type analysis you're asking. What I did is I looked at what has been recovered to date. And if you can't do poor volume analysis, you can't really relate it back to what's in the ground. You're just looking at what's happened to date.

And based upon your deliverability test data, which I addressed in my first comment, that problem can be overcome by drilling a vertical well.

The other comparison I made was to production to date. Clearly, the Howell and the Riddle have not had a disadvantage in getting the amount of production out of the ground when you compare their unit to the offset units.

Q. Does Amoco have plans to drill any highly deviated or high-angle wells in the Mesaverde formation?

A. We're evaluating it.

Q. What is the status?

A. I don't know -- you know, I can't say we're going to drill a well within a month or three months or a year, but I know that's being evaluated.

Q. What is the status of the evaluation at this point?

A. I don't really know.

Q. You don't know where you are on the process within the company of deciding whether you'll go forward?

A. No.

Q. I presume, because you don't have such an application, that you're some distance removed from where Meridian is at this point in their project?

A. I do not work the Blanco-Mesaverde field.

The parties -- the engineers that work that have obviously a lot better handle on that.

Q. Do you know what your engineers that work this particular reservoir and are involved in studying the high-angle wells, what they're proposing to do about the allowable for Amoco?

A. I reviewed in detail -- obviously, if this is something Amoco is going to turn around and ask for, it would be foolish for me to come in and protest it. I reviewed in detail whether the recommendation we are proposing is something we are willing to live with. And the answer was yes.

Q. Simply because the current allowable system doesn't have provision for an allowable for a highly deviated well doesn't preclude the Commission from creating a special project allowable for these wells, does it?

A. No.

Q. There are no other highly deviated wells such as this that you're aware of in the Mesaverde Pool, are there?

A. Not to my knowledge.

Q. Certainly not in the San Juan Basin; right?

A. I can't answer for a large area but for the Blanco-Mesaverde. I can answer that I don't know of any others.

Q. Does your company have any well like this in any other of the producing pools in the San Juan Basin?

A. We've drilled horizontal -- not in the San Juan Basin; I'm sorry.

MR. KELLAHIN: Thank you, sir.

CHAIRMAN LEMAY: Thank you, Mr. Kellahin. Additional questions? Mr. Weiss?

FURTHER EXAMINATION

BY COMMISSIONER WEISS:

Q. Is Amoco satisfied with the method that Meridian uses to publicize, say, their efforts in the coal gas, their development techniques and such and their completion techniques or their technology in general?

A. Unfortunately, though I am responsible for New Mexico, the one area in New Mexico I'm not responsible is coal D gas. I know that Mr. Nance, who is sitting in the audience, was in our office in Denver yesterday talking about that, but to say whether we're satisfied or not, I can't answer that.

Q. I have one other question. I guess I'm confused on this cap. Maybe you can explain it to me.

If this proposed well would make -- had a "D" of 20 million a day, it would only be allowed to produce 16 million is the way I understand it?

A. Or whatever is the highest. If Meridian goes and drills a well tomorrow that comes in at 50 million based on their cap, the cap would then go to 50 million a day.

But to answer your question directly, yes.

Q. So it's based on the best well in the field?

A. Best unit. It's a little confusing, but I think they meant the best unit production out of a vertical drilled unit.

COMMISSIONER WEISS: Thank you. That's all the questions I have.

FURTHER EXAMINATION

BY CHAIRMAN LEMAY:

Q. Mr. Emmons, do you happen to know if Amoco happened to have a policy on granting maybe an incentive allowable for encouraging new technology and balancing the risk encountered in using that new technology?

A. I don't have any knowledge firsthand. They may; they may not, but I don't have any knowledge on that.

Q. Would you care to comment on regulatory approaches that do encourage new technology through allowable increases?

A. I think that has a lot of merit. Unfortunately, here, we're talking about a prorated pool that not only Meridian but also Amoco has concerns about how the allocations are currently being handled. I'm participating as well as Meridian is participating on a subcommittee that's part of the overall committee, trying to make changes in the rules.

That very well could be brought up as a recommendation, and let's change it for the entire pool instead of doing it on a special exception basis, well by well or unit by unit.

I guess my feelings are, let's make sure we look at the entire pool and make sure it's fair to the entire pool. What I tried to do is point out today some of the concerns I have when you apply it in a limited nature.

Q. Extending that, though, it has to start somewhere, doesn't it? If you're going to apply an incentive allowable somewhere that would be a policy throughout that pool, you would start with an application, I would assume?

A. But you may be providing an incentive allowable by just making them use the horizontal well plus one of the other wells.

I haven't heard them say they won't drill it if they take our proposal. That was asked. I don't believe we got a direct answer on it. So you may in fact -- they expect to get a better well. There's no question. If they don't, then I don't understand why they're here.

So you may be in fact providing that incentive allowable because, if the well acts like two vertical wells, and you throw in another one of the vertical wells, you provide them an incentive allowable adding in one of the other vertical wells, essentially taking three vertical wells and adding them together.

Q. Was it your testimony that no one knows if a diagonal well will increase the ultimate recovery from the proration unit?

A. What I'm saying is, I agree with Meridian that there's a lot of unknowns today. If their deviated well does not encounter any better permeability than what a typical vertical well would get, then they may not have any positive results from it. But I think there's also the same likelihood they may encounter new sands; therefore, have additional recovery, but that may have also been accomplished by drilling another vertical well.

I just don't know enough about it today to say in advance whether they're going to get additional reserves or not. I think there's a chance that they will.

Q. In that same vein, if you say another vertical well, you would be amenable to allowing three wells in a proration unit and having the operator be able to choose the best two out of the three, if he was so inclined, to increase his ultimate recovery?

A. The deviated well throws in kind of a kink in that. The reason I'm not limiting Meridian with the deviated well is because I think there's probably a good chance that they will not get all the production out of both quarter sections. They may actually get the predominant production out of a quarter section. Without forcing Meridian to go in there and test to find out really where their production is coming from, we don't know which well to pair it up with.

So to remove that obligation, I'm saying they can use the horizontal well plus any of the other two. That's not to say that I think when we start drilling three vertical wells in a unit that they have to not include the offset unit -- an offset quarter section. I still feel that's a proper requirement.

CHAIRMAN LEMAY: I have no further questions. Thank you.

Any additional questions of the witness? If not, he may be excused. Thank you.

MR. LUND: We have nothing further, Mr. Chairman.

CHAIRMAN LEMAY: Are there any statements in this case? Do you care to wrap it up, Counselor?

MR. KELLAHIN: Mr. Chairman, I don't know if the Commission has additional questions. We have a number of technical people that can quickly respond if there's any further questions. I don't presume to know what is of concern to you in the case. We've done what we can to give you the background information. If there's other information you want from us or want to recall a witness, we certainly still have them available.

CHAIRMAN LEMAY: Let me check with Commissioner Weiss. We keep that option open, as you know.

I think with the incorporation of the record of the previous case and what we've heard today that we certainly have enough evidence to make our decision, Counselor.

MR. KELLAHIN: We're ready to conclude then, Mr. Chairman.

CHAIRMAN LEMAY: Let's conclude.

MR. LUND: We've all heard enough today, and the only point that I would make, with all due respect to Meridian, I think that they have a very good idea, and I understand their technological concerns, but what they want to do is cherry pick, and I know that was objected to earlier when I suggested that. They want to get a production cap, and they come in here and say, "Well, we're going to give the Commission something that we did not give Mr. Catanach the opportunity to consider. We're going to put this production cap in there." But it's cherry picking, and it's unfair for the reasons that Mr. Emmons testified.

We do not oppose the technology. We do not oppose this project. We think it's a great suggestion. But it's unfair to the offsets. It's unfair to those who are concerned about correlative rights to allow Meridian to get what they're asking in this case.

The final thing I would say is that I think

Mr. Catanach in his order very appropriately summed up our concern. In his Findings 12 and 13, he talked about the concerns for correlative rights and the unfair advantage that Meridian would be seeking in this case. And for the reasons that Mr. Emmons testified to, we respectfully request that their request be denied, and that you adopt the proposal that Amoco has suggested. We think that would give them a fair opportunity to generate a return for the dollars that they've been spending and also protect correlative rights.

With all due respect, it's simply not fair to grant the Meridian request as stated today. Thank you.

CHAIRMAN LEMAY: Thank you, Mr. Lund. Mr. Kellahin?

MR. KELLAHIN: Gentlemen, Mr. Lund wants you to focus on correlative rights. He says it's unfair. It somehow gives us an unfair advantage over Amoco; yet, despite their involvement in this case from September onward, they have provided you nothing by which to determine the extent of their correlative rights and to what extent you must protect them. They have not given us what they believe to be the gas in place underneath their spacing units, or why the establishment of a special project allowable should somehow be unfair to them.

The concern that we have is that Mr. Catanach has also put the wrong emphasis on what he was doing when he wrote the Examiner order. The fundamental obligation of the Commission and the Examiner is to prevent waste. It is not simply to look solely at the correlative rights issue; particularly, in a case like this, where it's so subjective and so hard to quantify. Who are we to say that twice the deliverability is going to impair anyone? There's some doubts as to whether this well is going to be as good. It's a vertical well. So the speculation on correlative rights is really not what we ought to be concerned about.

It's undisputed that prevention of waste is the paramount obligation of this Commission. It's been set forth in cases that have gone to the New Mexico Supreme Court. That's your fundamental obligation. There is absolutely no disagreement in this case that a pilot project -- and we're not asking for blanket rules for all highly deviated wells in the Mesaverde. We're looking for a project incentive that makes this economically viable so that we can do what Mr. Catanach has found that we ought to be doing. And that is to drill these wells to prevent waste.

Mr. Clayton told you his position and that of his company far more eloquently than I can, but the one thought that sticks in my mind from all the discussion this morning is why should we be penalized for the opportunity to enjoy success in this reservoir? And that's all we're asking you for. We're not asking you for a blank check. We've proposed some limitations on how we might operate this.

If you'll look at the transcript, I think it's interesting to look at the exchange between Mr. Catanach and Mr. Jones, and that demonstrates why I think Mr. Catanach had the wrong focus and emphasis when he wrote the very findings that Mr. Lund wants to draw your attention to.

He presumed in his question to Mr. Lund that approval of this application was going to harm the offsets, and he posed the question in that fashion. He presumed a question for which there was only one answer: if this project harms other operators in the pool. Harm, I would define as impairing their correlative rights. And this Commission always has retained jurisdiction of all your orders. In fact, you've got the fundamental obligation if subsequent evidence demonstrates to you that harm is occurring with this project, you can set a show cause hearing and bring us back in the next day. You're not writing a check for us that we fill in the amount and we're not accountable to you ever. That's certainly not true. You always have the ultimate power to determine what we do.

And what better way to judge what happens with the Mesaverde than to test it with a pilot project? This is the way we historically do these kinds of things, and any new technology normally goes through a cycle of pilot project. This particular project needs an economic incentive, a special project allowable.

And there's some logic to what we've discussed for you. It's a single wellbore that penetrates both halves of the spacing units, and why not double the "D" for that? It sounds reasonable to me. I'm not a technical person, but it just seems to make sense that that should be a choice when you've penetrated both halves of the 160 with this deviated well, that you have the choice of taking that or the other two vertical wells and calculating your allowable.

This is a technology whose time has come, and we want the opportunity, if you'll permit us, to exercise the chance to see if we can't recover reserves that might not otherwise be produced in this reservoir. It's not unusual for this Commission to encourage the development and use of additional technology. We request that you not unreasonably restrain yourselves as regulators and remove the flexibility from us as operators in order to test this project.

You provided that to Mr. Merrion not long ago in Order R-9079. Now he's got a horizontal directionally drilled pilot project. Admittedly, this is an oil reservoir, and you might want to make a distinction, but this Commission provides those kinds of incentives. Mr. Merrion had a bonus allowable in here. He had a special project allowable that was higher than his depth bracket oil allowable.

We're not asking you for something unusual. We're simply asking to make this project work, to test the technology, and let us do it now before we lose the opportunity to exercise this and bring it back to you and show whether or not it can be a success or not, and that's all we're asking.

CHAIRMAN LEMAY: Thank you, Mr. Kellahin.

Is there anything additional in these

cases? If not, the Commission will take them under advisement. Thank you.

CERTIFICATE OF REPORTER

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

I, Carla Diane Rodriguez, Certified Shorthand Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation Commission was reported by me; that I caused my notes to be transcribed under my personal supervision; and that the foregoing is a true and accurate record of the proceedings.

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

WITNESS MY HAND AND SEAL March 2, 1990.

Carla Diane Rodriguez

CARLA DIANE RODRIGUEZ
CSR No. 91

My commission expires: May 25, 1991

CERTIFICATE OF REPORTER

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

I, Deborah O'Bine, Certified Shorthand Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation Commission was reported by me; that I caused my notes to be transcribed under my personal supervision; and that the foregoing is a true and accurate record of the proceedings.

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

WITNESS MY HAND AND SEAL March 2, 1989.

Deborah O'Bine

DEBORAH O'BINE
CSR No. 127

My commission expires: August 10, 1990