NEW MEXICO OIL CONSERVATION DIVISION

EXAMINER HEARING

SANTA FE, NEW MEXICO

Hearing Date JULY 24, 1997 Time 8:15 A.M.

NAME	REPRESENTING	LOCATION
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Paul [illegible]	Campbell Carr, Berge & Sheridan	Santa Fe
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BARRY [illegible]	[illegible]	[illegible]

STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:

APPLICATION OF CONOCO, INC., FOR THE ESTABLISHMENT OF A DOWNHOLE COMMINGLING REFERENCE CASE PURSUANT TO RULE 303.E AND AN EXCEPTION TO RULE 303.C.(1)(b)(ii), RIO ARRIBA COUNTY, NEW MEXICO

CASE NO. 11,815

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: MICHAEL E. STOGNER, Hearing Examiner

July 24th, 1997

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, MICHAEL E. STOGNER, Hearing Examiner, on Thursday, July 24th, 1997, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

* * *

I N D E X

July 24th, 1997
Examiner Hearing
CASE NO. 11,815

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A P P E A R A N C E S

FOR THE APPLICANT:

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

ALSO PRESENT:

ERNIE BUSCH, Geologist
Aztec District Office, NMOCD

* * *

WHEREUPON, the following proceedings were had at 8:20 a.m.:

EXAMINER STOGNER: This hearing will come to order for Docket Number 22-97. Please note today's date, Thursday, July 24th, 1997. I'm Michael Stogner, appointed Hearing Examiner for today's cases.

At this time I'll call Case Number 11,815, which is the Application of Conoco, Inc., for the establishment of a downhole commingling reference case pursuant to Rule 303.E and an exception to Rule 303.C.(1)(b)(ii), Rio Arriba County, New Mexico.

At this time I'll call for appearances.

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

EXAMINER STOGNER: Any other appearances?

Will the witnesses please stand to be sworn at this time?

(Thereupon, the witnesses were sworn.)

EXAMINER STOGNER: Mr. Kellahin.

MR. KELLAHIN: Mr. Examiner, in this case I have two witnesses to present to you. The first is a geologic presentation to simply give you an overview of the various San Juan Basin reservoirs that have been produced in the 28 and 7 Unit by Conoco and others. Conoco is the current operator of that unit.

After the geologic presentation, then we'll have an engineering presentation.

We're specifically looking for a reference case, and by that we mean approval to process the downhole commingling applications for wells within the 28 and 7, using certain technical information we're presenting today, in order to satisfy the requirements for downhole commingling.

We're going to present to you a request that you grant an exception from Rule 303 C. The C(1)(b)(ii) section is the pressure limitation rules for commingling. Those rules currently require, in the absence of other evidence, that the commingled pressure be such that the highest pressured zone to be commingled cannot be higher than the original reservoir pressure of the lowest-pressured reservoir to be commingled.

We believe at this point there is definitive pressure information in the unit to justify an exception from that particular rule.

In addition, we are asking you to eliminate the requirement that each administrative commingled application be sent to each interest owner. The problem in this very large unit is that it is a divided unit where you have various participating areas which are not the same size. The consequence is that in virtually every commingling case you'll have different ownership.

What we're asking you to do in this case is what you've done for other operators in the San Juan Basin, is to not require us to send notification of each of these cases to all these interest owners.

The Application in this case and the notice to all those people clearly puts them on notice that we're seeking to have that rule exempted from operation in the unit.

In addition, we're going to provide you evidence of the types of allocation formulas we want you to approve for the unit so that when we use those forms and submit them to the District, where the specific data is identified for that particular well, the District will know and we will know that the allocation formulas have been approved by the Division.

In addition, we're asking you to declare all of the producing formations in the unit -- with the exception of the Mesaverde -- that you declare all those other pools to be marginal. The reason is that in order to commingle production, as you know, we must demonstrate that at least one of the zones to be commingled is marginal. We believe we have definitive evidence on that issue, and we'll ask you to find accordingly.

There will be a general presentation of the overall benefits of commingling in the unit and why that is an operational necessity late in the life of a unit like this. And as we look for remaining recoverable gas, the way we're going to be able to produce it is through commingling operations, as opposed to any other type of wellbore.

And that's our presentation, Mr. Examiner.

With that introduction, let me call my first witness.

THOMAS B. JOHNSON,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Will you please state your name and occupation?

A. My name is Thomas B. Johnson, and I'm a geologist employed by Conoco.

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

A. Yes, I have.

Q. Pursuant to your employment as a geologist for Conoco, have you made a geologic investigation of the various reservoirs that have been found to be productive within the 28 and 7 unit?

A. Yes, I have.

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

EXAMINER STOGNER: Mr. Johnson is so qualified.

Q. (By Mr. Kellahin) Mr. Johnson, let's show Mr. Stogner the general overview of the geologic interpretation, and as we do that we can show him the status of development for that particular reservoir.

Let's start first of all with what is marked as Exhibit Number 1 so that he can see the locator map that identifies all the various types of wells that are produced in the 28 and 7.

Would you look at that for me, Mr. Johnson, and identify it?

A. Yes, Exhibit Number 1 is a map that covers all of the 28-7 Unit, which encompasses all of 28 North, 7 West, and a portion of 27 North, 7 West.

The plat that you have in front of you, you can see each section on there. There's no scale directly written on here, but you can see a mile as indicated by the section lines, which are outlined in blue.

There are some 389 total completions that have been made in 28-7 through May, 1997. Those are indicated by the colored dots shown on the plat. The red dots show the Dakota production, green dots show Mesaverde production, blue dots show Chacra production, the larger black dots show Pictured Cliffs production, and the small dot shows Fruitland Coal production.

Posted by each of those is the well number.

Q. When we look at Exhibit Number 1, there are various lines of cross-section shown on this display; is that not true?

A. Yes, that's correct. There's five lines of cross-section thrown on here, labeled C-C', D-D', P-P', M-M' and F-F'. I do not intend to show those cross-sections today, but they are available if necessary.

Q. All right, let's turn to the geologic identification plat, Exhibit Number 2. Identify and describe this display for us.

A. Okay, Exhibit Number 2 is a time-stratigraphic chart of the San Juan Basin after Molenaar. It shows all the Cretaceous producing reservoirs that I just mentioned from Exhibit Number 1.

Starting from the bottom, the deepest and one of the two best producing horizons in the unit, the Dakota, I encountered an average depth of around 7500 feet. It's a tight-gas sand, predominantly fluvial interspace and becoming increasing more marine toward the top. There are several members, the Twowells and Paguate sands, though, being the most consistently developed in the Dakota.

Moving up from there, the Point Lookout sandstone consists of three members, the Cliffhouse, The Menefee and the Point Lookout. They're found at an average depth of around 5150 feet mid-perf, transgressive and regressive nearshore marine sandstones, also a tight formation, very low perm. Cliffhouse and Menefee -- Cliffhouse and Point Lookout are best developed in the northeast part of the unit, as reservoir quality deteriorates across the southwest portion of the unit.

Moving uphole from there, the Chacra sandstone, productive predominantly in the southwest portion of the unit, the Pictured Cliffs Sandstone, representing near -- still stands of the regressing Cretaceous seaway, and then finally the Fruitland Coal formation, found at depths of around 3000 for the Fruitland, 3100 for the PC and 3800 for the Chacra.

Q. Mr. Johnson, let me have you take the next three displays, and if you'll take Exhibit 3, 4, and 5, let me have you put those out in front of you, and let's talk for a moment about the structural component of the various pools within the unit. Exhibit 3 starts at the deeper horizon, Exhibit 4 is in the middle portion with the Cliffhouse, and then finally Number 5 with the Pictured Cliff.

A. That's correct. I picked three, one from the shallow, one from the medium and one from the deep, just to show that the structure in the unit is consistent from top to bottom.

Structure is just irregular regional dip from northwest, and dipping to the -- from the southwest, dipping to the northeast, we see the darker colors that represents a deeper depth. Dip is approximately 50 to 100 feet per mile.

This just emphasizes that the traps in 28-7 are purely stratigraphic traps, and they're not structural in nature.

Q. When we look at the various pools in a moment, are we at a point in the development of the unit where it is highly improbable that you're going to encounter significant gas production in any of these pools that you could characterize as being substantially commercial?

A. It's getting to the point now where the best locations have been drilled.

Q. As we move to any other development, then, is it likely to be marginal in areas that have not yet been drilled in the unit?

A. Yes, that's correct.

Q. Is it also highly unusual that anywhere in the unit you would encounter a new portion of any of these pools that would produce substantial volumes of gas that you could characterize as being commercial?

A. I don't think we'll find any surprises in that regard. There are a significant number of penetrations all across the unit at this point in time.

Q. All right. Let's turn, then, to the maps that show the extent of development, starting in the Dakota, pulling Exhibit 6 out and showing it side by side with the production map you're demonstrating as Exhibit 7. Let's look at 6 and 7 together.

A. Okay. Again, 6 and 7 show the whole 28-7 Unit with a little bit of a border around the unit in this case. There are some 139 Dakota completions that are shown on these maps. You can see that there are wells drilled from the north to south all across the unit in the Dakota.

If you look at the cumulative production map here, the contours start at a low of 200, go up to 400 and then jump to a BCF, 2 BCF, 3 BCF and 4 BCF at the extreme case. The average EUR for these wells is about 1.2 BCF.

If you look at the consistency of the colors again, the lighter colors represent the lower cumulative production. You can see that the development of the Dakota is fairly consistent across the unit.

As I mentioned earlier, the two wells from the Paguate are two main producing zones in the Dakota, and they are fairly consistently developed all across the unit.

Q. What has been the extent of your personal involvement with the geologic portion of this unit, Mr. Johnson?

A. We were -- Ever since we took over operatorship, I have been the geologist in the unit and have been working on all the development drilling programs and the recompletion program that Conoco has been carrying out.

Q. And how long a period of time has that been?

A. We took over -- We've had operatorship for a little over two years now.

Q. We've looked at the Dakota. Now let's turn to the Mesaverde. If you'll take Exhibit 8 and 9, and again draw us to the significant points of these two displays.

A. Okay. The map covers the same area as the Dakota map we just looked at. There are some 125 completions in the Mesaverde across the unit.

You can see, as opposed to the Dakota, that the bulk of the Mesaverde wells are concentrated in the northeast portion of the unit. That is because in the northeast portion of the unit you have well developed sands in both the Cliffhouse and the Point Lookout members of the Mesaverde. As you move to the southwest, across the unit, those formations -- development of those formations starts to deteriorate and their productivity decreases significantly.

Contour intervals, here again, the darker intervals represent the higher cums. The lows here are 200-MCF contours, ranging up to 4 BCF in the darkest red.

Q. As we look at the Mesaverde and try to rank it among the rest of the reservoirs in the unit, where would you rank this reservoir in terms of its remaining potential?

A. Remaining potential, it is one of the better formations left in the unit, although most of the better Point Lookout, Cliffhouse, Menefee locations in the Mesaverde have been drilled.

Q. Despite the fact that this is ranked the best of the pools left to be produced, it's been substantially developed?

A. Yes, sir, it has.

Q. As we move to the south and western portion of the unit, do you have sufficient enough tests in the Mesaverde to satisfy yourself that that portion of the unit is going to be less productive than what was developed in the northeast corner?

A. Yes, we do.

Q. All right, let's turn to the comparison of the Chacra again, with the locator map and then the cum map, Exhibits 10 and 11.

A. Okay, again covering the same areas, Exhibit Number 10 shows the 27 Chacra completions made in the unit to date. You can see they're located in the extreme southwest portion of the unit in all cases.

The highest-cum wells in the Chacra are located in the extreme southwest. In Section 30 and 29 we have cums of 500 million to 700 million cubic feet of gas. They deteriorate rapidly to the northeast from there. In the extreme southwest we do have several sands developed, several porosity developments in the Chacra which rapidly deteriorate to the northeast. You end up with one small zone, really a secondary, marginal zone.

Q. What's the explanation for the absence of Chacra production above the southwestern portion of the unit?

A. It's really a reservoir-development issue. The recoveries that you get out of those, unless you can recomplete at a very low cost, it wouldn't be worth adding those zones in a well, or drilling for them certainly.

As I said, in the very southwest portion of the unit there are two sands developed, two porosity intervals. Then as you move to the northeast you lose them down to one, and it deteriorates further to the northeast beyond that.

Q. Has there been sufficient development and tests of the Chacra to give you a reasonable proximity as to the northeastern boundary of the Chacra production?

A. Yes, at approximately the limit to the northeast where you see the last line of wells there in Section 31 of 28-7, Section 5 of 27-7 and Section 9.

Q. All right, let's turn to the Pictured Cliffs. Again, looking at Exhibits 12 and 13, describe for us your geologic conclusions about the Pictured Cliffs.

A. Again, this covers the same area, all of the 28-7 Unit with a small border. It shows the approximately 100 Pictured Cliffs completions that have been made in the unit. Again, most of the completions in the Pictured Cliffs are in the southwest portion of the unit.

If you look on the production map, which goes up to a high of 3 BCF in one instance with the darker colors here, you can see running through the southwest portion of the unit one of the Pictured Cliffs benches that runs through the San Juan Basin. You can see the dark red running from Section 6 down to Section 16 and then out into the Rincon Unit to the southeast.

These benches, which represent still stands of retreating Cretaceous seaway, really end -- If you look at a larger view of the San Juan Basin, this would be the northeastmost bench, or one of the very northeastmost benches that goes through the entire San Juan Basin. To the north of this the reservoir development is not as good as it is to the southwest in the unit and in the rest of the Basin.

Q. Finally, let's turn to the Fruitland Coal gas, if you'll look at Exhibits 14 and 15 and give us your conclusions.

A. Okay, Fruitland Coal, there are 15 wells completed in the Fruitland Coal. One of them, or two of them, was drilled as close away as a nitrogen injection well. Amoco had a nitrogen injection project, which they have ceased to inject into, in the 28-7 Unit.

Coal is relatively consistently developed across the unit, 50 or so feet of coal in two or three packages.

The production is marginal again. We expect about 100 MCFD out of a Fruitland Coal recompletion. It's not a good drill candidate, and very few wells have completed it in the unit to date. Best wells on this entire map show cums to date of around 500 million cubic feet.

Q. From a geologic perspective, Mr. Johnson, what do you see as the remaining future opportunities in the unit to produce the remaining gas reserves from all of these pools?

A. Well, we need to drill and produce all of these in as few completions as we can, in as few wellbores as we can, commingling to keep our costs down since we can't afford to drill wells for these marginal zones. Being able to combine them in a single wellbore would save us a lot of money and let us produce these zones.

MR. KELLAHIN: That concludes my examination of Mr. Johnson. We move the introduction of his Exhibits 1 through 15.

EXAMINER STOGNER: Exhibits 1 through 15 will be admitted into evidence at this time.

EXAMINATION

BY EXAMINER STOGNER:

Q. What's the chronology of the production in this unit, historically?

A. It started back in the 1950s with the first pass of Mesaverde development. If you hold on for just one second -- Yeah, the earliest Mesaverde production occurred back in the early 1950s. That's when -- The initial pass was drilling all across the San Juan Basin.

With the series of infill drilling that we had -- I believe it was in the Seventies -- when they allowed the increased drilling, allow the second well on a 320 Dakota production. The earliest wells were drilled in the late Fifties and early Sixties. First production on most of these wells in the Dakota was through the Seventies and on into the early Eighties.

And Pictured Cliff production pretty much followed Measaverde. Most of their early development occurred back in the early to mid-1950s, with most of it finished in the Sixties and early Seventies.

Q. Do you know when the last well was drilled in this area?

A. Well, we're drilling wells in there right now.

Q. What type of wells?

A. We're drilling Mesaverde-Dakota downhole commingle wells.

Q. Okay. Are those new wells scattered throughout the unit, or are they --

A. No, the --

Q. -- concentrated in one area?

A. The new wells are concentrated in the northeast portion of the unit. We had locations that had not previously developed by Amoco or El Paso or by previous operator Amoco. We targeted those for development, and we are drilling -- We have a ten-well program ongoing this year. We drilled nine wells last year, we're drilling ten wells this year. And they're all in the northwest -- in the northeast portion of the unit, where we have development in both the Cliffhouse and the Point Lookout portion of the Mesaverde, and these wells below the Dakota as well.

Q. In looking over some of these maps, there are abandonment marks on some of those wells. Are those primarily just zone abandonments, or are there some plugged and abandoned wells?

A. There are some plugged and abandoned wells in the unit. Some of those represent zone abandonments. If you're looking at the deeper Dakota zones, especially, some of those wells have been plugged back by us, some by previous operators.

So not -- When I said initially that -- the 389 wells on that plat we looked at, that represents all the completions that have ever been made in the unit.

Q. Okay. So the completion numbers you give me aren't necessarily the number which is currently producing?

A. That's correct.

EXAMINER STOGNER: Mr. Busch of our Aztec District Office is in the audience today. Do you have any questions, Mr. Busch?

MR. BUSCH: Yes, Mr. Stogner, of Mr. Johnson.

EXAMINER STOGNER: Why don't you come up here and make yourself comfortable in these seats here and...

EXAMINATION

BY MR. BUSCH:

Q. Mr. Johnson, of those ten Mesaverde wells in your new development of the Mesaverde, are you looking at the Lewis interval or that interval that's defined as being from the base of the Huerfanito bentonite marker down to the massive Cliffhouse?

A. We have not looked at that as a productive horizon in the 28-7 Unit to date.

Q. Okay. Do you have any 3-D seismic --

A. We have --

Q. -- information of this area?

A. We have just recently acquired some 3-D seismic in conjunction with the deep Pennsylvanian exploration program that's ongoing in the unit, but that has not been interpreted yet, as far the shallow horizons go. I don't even know if it will provide that much useful information in the shallow stratigraphic traps. It may, and it's something we'll investigate, but that is just recently acquired data.

MR. BUSCH: Okay. Thank you, Mr. Johnson. Those are all the questions I have.

EXAMINER STOGNER: Thank you, Mr. Busch.

MR. BUSCH: Thank you, Mr. Stogner.

EXAMINER STOGNER: You can go ahead and stay up there, Mr. Busch. That way -- Because I'm sure you'll have some other questions of the next witness.

Mr. Kellahin, any further redirect?

MR. KELLAHIN: No, sir, Mr. Examiner.

EXAMINER STOGNER: He may be excused at this time.

Mr. Kellahin?

MARK MAJCHER,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Would you please state your name and occupation?

A. My name is Mark Majcher, and I'm a reservoir engineer with Conoco.

Q. Mr. Majcher, for the court reporter will you spell your last name?

A. M-a-j-c-h-e-r.

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

A. Yes, I have.

Q. And you reside where, sir?

A. Midland, Texas.

Q. As part of your responsibilities as an engineer, have you made an engineering investigation of the relevant facts for the 28 and 7 Unit, insofar as determining whether or not downhole commingling is an appropriate means to pursue the recovery of the remaining gas within the unit from these various pools?

A. Yes, I have.

Q. And based upon that study, do you now have certain conclusions and recommendations for the Examiner?

A. Yes.

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

EXAMINER STOGNER: Mr. Majcher is so qualified.

Q. (By Mr. Kellahin) Before we talk about the specifics of your engineering study, let's talk about the general parts of your presentation.

First of all, have you compiled for the Examiner some general, overview reservoir information for the San Juan 28 and 7 Unit?

A. Yes, the first part will be a brief overview and summary of the production statistics of the 28-7.

Q. After that, have you turned your attention to what I will call the pressure exception topic, in which you have reached conclusions about whether or not it's appropriate to grant an exception unit for the -- from the pressure-limitation rules that apply to downhole commingling?

A. Yes, I've compiled reservoir pressure data, both under initial conditions and current conditions, as well as those of recent new drills, and I have done analysis on that data, as well as fracture-stimulation data, comparison and buildup calculations.

Q. Okay. Based upon your study of the pressure-buildup calculations and your analysis of the fracture gradients, you now have engineering conclusions with regards to granting an exception for commingled production in the unit from the pressure rule?

A. Yes.

Q. In addition, have you made a study and are you prepared to present to the Examiner the various benefits of downhole commingling versus other types of wellbore configurations?

A. Yes.

Q. And fourth, have you compiled for the Examiner your recommendations concerning the types of allocation formulas that you're seeking to have approved and applied to production in the unit?

A. I have.

Q. And then finally, have you made a study of the economics of the various pools to determine which ones of them can be characterized by the Division as marginal?

A. Yes.

Q. Let's go back, then, and start with the first of your presentation, Mr. Majcher. If you'll turn to what is marked as Conoco Exhibit Number 1, let's take a moment and identify that display.

A. The Exhibit here, Number 16 --

Q. Yes, sir.

A. -- is a production plot of total unit gas production for the 28-7 Unit. First production was in January of 1953; this plot only goes back to 1970, however.

As you can see, the unit makes approximately 37 million cubic feet of gas a day, and the gas cum to date has been just under 339 BCF.

Q. Let's turn and look at the summary on Exhibit 17 of the various informations from the pools.

A. Exhibit 17 is a production summary of the reservoir by producing horizon. It lists the first production dates, total number of completions, the number of active wells, cumulative gas per reservoir, daily gas rate per reservoir, and average rate per well of that reservoir, and also the average depth.

It's clear from this table that the majority of the production comes from the Mesaverde and Dakota, and they combine for approximately 33 million cubic feet of gas a day.

Q. What do you, Mr. Majcher, see to be the method by which Conoco can maximize the recovery of the remaining gas from these various reservoirs within the unit?

A. Well, we need to continue developing the Mesaverde and Dakota as development drilling projects and access the Fruitland Coal, PC and Chacra reserves with selective recompletions.

Q. What method of wellbore configuration is the optimum method in the unit by which to maximize the gas recovery?

A. From the Mesaverde-Dakota it would be -- Well, for all of them, really, it would be a commingle scenario.

Q. One of the rules for commingling when you file these administrative applications sets a benchmark for pressure whereby the commingle zones have to meet a pressure criteria such that the highest pressured zone, unless otherwise exempted by the Division, cannot exceed the original reservoir pressure of the lowest pressured zone. You're aware of that?

A. Yes.

Q. Have you studied that issue of pressure within the San Juan 28 and 7 Unit?

A. Yes, I have.

Q. And what conclusion have you reached?

A. My conclusion is that the pressure exemption for the Mesaverde and Dakota should be granted for new drills in the 28-7, because the average Dakota pressure is below the original Mesaverde pressure.

In addition, although the initial Dakota pressure of recent new drills exceeds the original Mesaverde pressure, I will present data that shows that no damage will occur to the Mesaverde.

Q. How have you supported that conclusion and recommendation?

A. I've supported it through analysis of the available pressure data, and through comparison of that data with the actual measured frac gradients for recent stimulations of the Mesaverde, and also through pressure buildup calculations.

Q. What is the benefit to the unit of having this type of exception from the pressure rule granted for the unit?

A. The ultimate benefit would be increased gas recovery and increased value to the operator and interest owners through immediate commingling.

Q. Describe for me why that benefit occurs. In what particular way?

A. If granted the exception, the Mesaverde-Dakota can be commingled immediately and that gas production realized more quickly.

Q. All right, let's give an example. If you have a new drill that's been approved for commingling but you have to satisfy the current pressure requirement --

A. Yes.

Q. -- and you find that you have a Dakota pressure that is higher than the original reservoir pressure in the

Mesaverde, then you cannot commingle until the pressure in the Dakota has been reduced; is that not true?

A. Conoco was granted an exception for a certain number of wells two years ago, and those wells had been drilled and produced with the pressure exemption, with no ill effect.

Q. All right. Let's assume you had not had that pressure exemption granted for those wells and had to abide by that pressure limitation.

A. Right.

Q. How, then, do you produce the well?

A. You would have to produce the Dakota until the pressure has been reduced to below the original Mesaverde pressure.

Q. All right, let's assume you do that. Then what do you have to do in order to convert this to a commingled wellbore?

A. You would have to spend the money to rig up on the well, pull the well, run back, in and also delay that production some time amount, whatever that may be.

Q. You made reference, Mr. Majcher, to prior approval of a pressure exemption for certain new drills in the 28 and 7 Unit.

Mr. Examiner, the witness is referring to a case. It's 11,349. It's Division Order R-10,476. It was entered effective October 6th of 1995.

All right, let's go back, then, and talk about the data that you're submitting that supports your conclusion about the appropriateness of an exception from the pressure limitation.

If you'll start with Exhibit 18, identify and describe what we're seeing here.

A. Exhibit 18, and also the next three exhibits, are pressure data information for various conditions. The first exhibit, Number 18, is a comparison of initial reservoir pressures by formation.

As you can see, it lists bottomhole pressure, the average mid-perf, the calculated gradient and then a bottomhole pressure at a datum, which I chose to be 5000 feet.

The original Mesaverde pressure was 1238 p.s.i. at the datum. The original Dakota was 2866 p.s.i. at the datum.

Q. Your choice of a 5000-foot datum point is not of significance, is it? In other words, if you had changed it to another datum point, you would simply have pressure adjusted to that datum point?

A. That's correct.

Q. The selection of 5000 feet is not unique as to the pressure?

A. It's not unique. I chose it because it is a nice round number, and it is close to the average Mesaverde perf'd interval.

Q. All right. Let's look at the next exhibit of information, Exhibit 19. Identify and describe what you're showing.

A. Exhibit 19 is a comparison of current reservoir pressure by formation, and this exhibit shows the average pressure of all wells in the formation, again adjusted to a common datum. For the Mesaverde that average pressure is 457 p.s.i. at the datum, and for the Dakota it's 713 p.s.i. Again that includes all wells, whether they be two months old or 20 years old.

I also included a column that lists the current pressures as a percent difference to the Dakota, just for comparative purposes.

Q. All right, let's make a comparison between Exhibits 19 and 18. Let's look at the Dakota. On Exhibit 19 you have a current average reservoir pressure in the Dakota of 713 pounds?

A. That's correct.

Q. How does that compare to the original reservoir pressure in the Dakota within the unit area? You'll find that on Exhibit 18, right?

A. Much less, yes.

Q. That would be the 2866?

A. 2866, down to 713.

Q. Okay. On average, using the current reservoir pressures in the unit for all these reservoirs, it appears that the current reservoir pressure is less than the original reservoir pressure of any of the reservoirs?

A. That's correct, if you go by the average of all the producing wells currently in the 28-7.

Q. Okay. Let's look at Exhibit 20 and have you identify and describe this display.

A. Exhibit 20 is a table of the initial reservoir pressures that we have seen through a recent drilling program. And everybody is familiar with the tight nature of these formations. So what we have seen is, while the average pressure is 750 p.s.i., the pressure of these recent new drills is considerably higher. In fact, when converted to bottomhole conditions, these nine wells have an average pressure of just over 2000 p.s.i. Again, that compares higher with the original Mesaverde pressure of 1230.

Q. All right, let's --

EXAMINER STOGNER: Mr. Kellahin, before we proceed --

MR. KELLAHIN: Sure.

EXAMINER STOGNER: -- may I interject here?

MR. KELLAHIN: Absolutely.

EXAMINER STOGNER: No, I'm not familiar with the tight nature of it. Why don't you explain that to me and how it's going to affect the pressure.

THE WITNESS: Okay, the Mesaverde-Dakota are classified as tight reservoirs. The average Dakota permeability is roughly .02, .025. The Mesaverde, I don't have an exact number but it's below .1.

What that does is, due to the tight nature, the transients can't flow, if you will, as quickly as if it were a non-tight reservoir, with higher permeability and porosity. This is why we're seeing initial pressures of these new drills. Although not virgin to the reservoir, they are higher than the average of what we see.

EXAMINER STOGNER: Okay. Thank you, Mr. Kellahin.

Q. (By Mr. Kellahin) If you'll look at Exhibit 20 and 18, then, let's draw an illustration of the issue you're addressing. If we look at 20, we find in some of the new drills in the unit the average pressure is just over 2000 pounds in the Dakota?

A. Yes.

Q. If you're required to abide by the current pressure rule and you propose to commingle Dakota with Mesaverde, and you look over on Exhibit 18, you find the original reservoir pressure in the Mesaverde of just over 1200 pounds, right?

A. Yes.

Q. Under the current rule, you could not commingle; is that not true?

A. That's correct.

Q. Have you examined whether or not the Mesaverde reservoir would be underpressured?

A. The Mesaverde is underpressured, based on your typical water gradient. It's slightly underpressured.

Q. All right. Let's explain what you mean by that terminology. Based upon your study of the fracture gradients in the Mesaverde, what do you conclude to be the highest fracture pressure required in order to fracture the container that confines the Mesaverde reservoir? What's that number?

A. Well, actually, I have a few exhibits to demonstrate that.

Q. I understand. Just give me the number, though.

A. The average frac gradient for the Mesaverde is a .52 p.s.i. per foot.

Q. And that would translate, then, to what type of reservoir pressure in the Mesaverde in order to fracture that container?

A. That translates to approximately 3800 pounds.

Q. All right. So if we're living with a rule that compares the original reservoir pressure in the Mesaverde as the benchmark, the 1200 pounds, that's a very conservative number if the purpose is to keep from fracturing the Mesaverde container?

A. Yes.

Q. Because you could pressure up the Mesaverde to an original reservoir pressure of approaching 3000 p.s.i. and still not fracture the reservoir container that contains the Mesaverde gas?

A. Based on actual frac data, yes.

Q. All right. Based on the actual frac data, then, if it's fracturing the Mesaverde at 3000-plus pounds, can you commingle that production with Dakota in the new drills where the Dakota pressure is 2000 pounds?

A. Yes, you could safely commingle.

Q. And that's what you have analyzed, is it not?

A. Yes.

Q. Let's look, then, at that part of the analysis.

A. Okay.

Q. If you'll turn to Exhibit -- Well, let's take a slight detour. Have you identify for us 21, which is your Mesaverde pressures.

A. Twenty-one is a similar exhibit to 20, although it addresses the recent pressures of the Mesaverde reservoirs. And again, it -- the resultant pressure is 858 p.s.i., which is nearly double the average of 458 for the average Mesaverde reservoir, again demonstrating the tight nature.

Q. All right. Let's turn to your pressure buildup calculations. You've got a summary sheet on Exhibit 22.

A. Okay.

Q. Let's talk about the methodology, and then we'll approach the conclusions.

A. Exhibit 22 is an example of pressure buildup calculations for an average Dakota new drill, those wells that you saw that have an initial pressure of around 2000, and it compares its relationship with the Mesaverde pressure.

Q. What's the purpose of the exercise?

A. The purpose of the exercise is to show that based on the reservoir data that we know about the Dakota and the current conditions of the initial new drills, that it takes a certain amount of time for it to build up and approach the original Mesaverde pressure. And my end result is that under normal operating conditions it's unlikely that we'll ever approach that.

Q. Okay. When you look at the values that go into the calculation, one of those values is to come up with some permeability numbers; is that not true?

A. That's correct.

Q. Have you satisfied yourself that you have selected accurate and reliable values to place into the calculation?

A. Yes, I have. The permeability calculation, in my opinion, is actually optimistic in that it is higher than we've seen from core data, but it matches well with Fetkovitch type curve matching, which was part of a big study done by an engineer two years ago.

The equation used is the pressure squared equation. I have the reference here of John Lee's *Well Testing* book, an SPE Textbook Series volume, and it's applicable for reservoirs less than 2000 pounds.

There's many factors that affect that equation, as you can see. The majority of those factors we have a good handle on. The two things that mainly affect it, of course, are your initial pressure and your producing time.

In this exercise I assumed, if you will, a virgin Dakota new drill, 2000 p.s.i., which I've shown in Exhibit 20, and I ran this calculation based on various producing times.

Q. All right. Let me set up the illustration when we look at the table below. Let's assume you've drilled your Dakota new drill.

A. Right.

Q. That you have initially produced it for 30 days, and then you shut it in. That is the first curve, it's the red curve on the display, is it not?

A. That's correct.

Q. All right. You shut the Dakota well in after 30 days. How long a period of time, under the calculation, does it take before the Dakota pressure in that well will build up to the original Mesaverde reservoir pressure of 1238 pounds?

A. It would take about 11 days.

Q. And so as we read the horizontal scale and read over and find the point where the red line intersects the Mesaverde pressure horizontal line, it's approximately 11 days?

A. That's correct.

Q. Let's assume that you shut your wellbore in for 180 days. Is that one of the curves displayed?

A. No, the hundred -- the dark --

Q. I'm sorry, I said that wrong. If you produce it for 180 days and then shut it in, how long would it take that well to build up before it exceeded the Mesaverde pressure?

A. Approximately 41 or 42 days.

Q. When you look at production in the unit, in the San Juan and 27 [*sic*] what is the expected longest shut-in period for a Dakota well?

A. Typically, shut-ins will occur once a year during plant shut downs, and those are normally two to three days to possibly 14 days.

Q. Under almost all operational conditions, then, for the Dakota wells, you would not have a shut-in period for more than 10 to 14 days?

A. That's correct.

Q. How likely is it, then, that you would have a Dakota well shut in long enough that it would have the opportunity to build up its pressure to a point where it exceeded the original Mesaverde pressure?

A. I would say there's little to no chance that it would ever do that. If we knew of an upcoming plant shutdown, it's unlikely that we would put an original well on until after that shutdown.

Q. All right. Let's take the unique situation where that unusual circumstance exists and a well in the Dakota is shut in for a long enough period of time that the pressure builds up to greater than 1238 pounds. Does that pose a risk to having the Mesaverde container fractured?

A. No, it does not.

Q. And how do you reach that conclusion?

A. Through fracture stimulation data, which is shown in Exhibit 23.

Q. Let's look at that.

A. Exhibit 23 lists the actual Mesaverde frac gradients from the 15 most recent stimulations. This information was provided by BJ Services, who was our lines vendor for acidizing and fracturing. It lists the well number and the frac gradients experienced per job for the three producing sands, Point Lookout, Menefee and Cliffhouse.

As you can see, the average of all three is a .52 gradient, and that is the pressure that's needed to be exerted on the formation to actually open up or fracture the formation.

Q. Have you taken the average Mesaverde fracture gradient, run through a calculation to show us what that pressure would be in the Mesaverde?

A. Yes, I have.

Q. And is that part of the information shown on Exhibit 24?

A. Yes, that's illustrated in Exhibit 24. The table at the top lists the average bottomhole pressure of the formation. If you look several columns over where it shows the pressure gradient, that is the actual pressure gradient. For the Dakota it's .2799. The frac gradient, again, for the Mesaverde is a .52.

What that says is that the Mesaverde frac gradient is some 86 percent greater than the pressure gradient that would be exerted on the formation if the Dakota were to build up to its maximum pressure. In fact, you would need a much higher pressure, closer to 4000 p.s.i., to approach the average Mesaverde frac gradient.

Q. What conclusion do you reach with regards to the possibility that Dakota new drills in the unit would have such a pressure that, if commingled with Mesaverde, you could exceed the fracture gradient of 3850 p.s.i. in the Mesaverde?

A. My conclusion is that you would never, ever reach it.

Q. Let's look at the bar chart at the bottom. What are you illustrating here?

A. This illustrates the measured frac gradient for each of the producing sands in the Mesaverde in reference to the Dakota pressure gradient of .28 and the average Mesaverde frac gradient of .52, and it's clear from this illustration that even the, quote, unquote, weakest sand, the Point Lookout, is considerably above the Dakota pressure gradient.

Q. Okay. Has Conoco had experience pursuant to the Division's approval for these new drills the Division approved back in October of 1995 in terms of commingling Mesaverde and Dakota? This was the order we talked about earlier.

A. I'm sorry, can you repeat the question?

Q. Yes, sir. Back in October of 1995, the Division entered Order R-10,476 that approved, I think, 17, if I'm not mistaken, new drills?

A. Yes.

Q. And they were approved as commingled Mesaverde and Dakota wells?

A. That's correct.

Q. Have you utilized that information available from some of those wells to make your analysis?

A. Yes, I have.

Q. And so based upon that experience, in addition to the other history in the unit, you're able to support a conclusion that we may delete the pressure-exemption requirement -- or limitation -- for Dakota-Mesaverde?

A. That is correct.

Q. All right. You're looking only at commingling Mesaverde and Dakota in terms of this pressure exception, right?

A. Yes, for new drills.

Q. And that's not intended to be an exception as to commingling Dakota with, say, Pictured Cliffs?

A. That's correct.

Q. All right. I think that concludes your discussion on that topic, does it not, Mr. Majcher?

A. Yes, it does.

Q. Let's turn to another topic. Let's have you illustrate and summarize your conclusions concerning the benefits of downhole commingling versus other types of wellbore configurations.

A. Okay, starting with Exhibit 25, the next four exhibits will illustrate the operational advantages and efficiencies of a commingling completion versus a dual completion for a typical Mesaverde Dakota well in the 28-7.

Q. All right, take us through these displays.

A. Exhibit 25 is a typical well schematic diagram of a dual completion and a commingled completion. As you can see, with a dual completion we use 5-1/2-inch casing with Dakota tubing of either 1-7/8 and 2-1/16. We have a packer in the hole to isolate the Mesaverde and Dakota. The Mesaverde tubing is either a 1 2/3 or 1 7/8, and we can run that with or without plungers, of course.

In the commingled completion, we have 4-1/2-inch casing, which is slightly cheaper, much larger tubing -- 2 3/8 or 2 7/8 -- and typically run a plunger lift system in that tubing configuration.

Q. Have you given us a summary sheet showing us the major advantages of commingling versus dual completion?

A. Yes, that's given as Exhibit 26, and there's three main operational advantages to commingling, the first being the ability to move more gas volume, which would increase your plunger efficiency, decrease your loading chances and ultimately maximize your gas production.

The second advantage is the ability to use larger tubing, which would enable you to lift more fluid with less pressure. This, again, increases plunger efficiency and maximizes your gas production.

The third major operational advantage is that, of course, operations are easier and less expensive. You're dealing with one string of tubing. You're not dealing with a packer in the hole. A packer makes it more difficult to operate a plunger because you have less annular volume, therefore less gas pressure to move the plunger.

All right, let's turn to Exhibit 27 and have you identify and describe this display.

A. Exhibit 27 provides data that will show the pressure effects on tubing sizes when running a plunger. You see the example of a 1-2/3-inch tubing versus a 2-3/8-inch tubing, and the data shows that with larger tubing you can lift the same amount of fluid with less pressure. For example, on a 1.9-inch tubing you can lift a quarter-barrel slug with 43 p.s.i. With 2-7/8-inch tubing, the same slug only requires 19 p.s.i. So again, the larger the tubing, the more efficient your plunger operations are, the less pressure is required.

Q. All right, let's turn to Exhibit 28.

A. Exhibit 28 shows the effect of tubing changeouts on production, and this was done on 35 total wells between November of 1996 and March of 1997.

The red and green bars show the sum of those 35 wells, both before and after the tubing changeouts. As you can see, the sum of the production went from just over 2.1 million to 3.8 million. Based on a per-well average, that was a 62-MCF-a-day before to a 109-MCF-a-day after. That represents a 77-percent production increase, just from changing out the 1.6- or 1.9-inch tubing to 2 3/8 or 2 7/8. It has a significant impact on your producing rates.

Q. The conclusion, then, in terms of the benefits?

A. By commingling, you could use larger tubing, and the impact on your producing rates are significant.

Q. Let's turn to the topic of your recommendation for allocation formulas to be approved by the Division for use in the unit. If you'll turn to Exhibit 29, there are two types of methods that are proposed for what you've characterized as newly drilled wells. Give us the summary of the methods you're asking approval for.

A. What I would like approval for is, for the Mesaverde-Dakota, PC and Chacra, the ability to use a fixed percentage allocation formula, and, for any operation involving the Fruitland Coal, the subtraction method.

Exhibit 29 outlines formulas for fixed-percentage allocation, for new drills, fairly standard, industrywide-accepted practices.

The first formula involves isolated zone testing of each zone individually. The second one, which I call the alternate allocation formula, allows for the testing of one zone individually and then the testing of the commingled stream, and then you can back it out that way.

Q. What sets the Fruitland Coal apart from the other reservoirs in terms of fixing a reliable allocation formula?

A. Well, it has different producing characteristics, which I will show through production plots.

Q. All right. With the exception, then, of the Fruitland Coal have you satisfied yourself that you can take a measured rate and then establish a fixed-percentage allocation between the commingled zones that is reliable for the remaining productive life of the commingled streams?

A. Yes.

Q. And we have illustrations to show how you got to that conclusion?

A. Yes.

Q. All right, let's talk about the recompletions.

If you'll look at Exhibit 30, let's talk about your allocation methodology for a recompletion.

A. Exhibit 30 shows the allocation methodology for recompletions, and also any commingle involving the Fruitland Coal. And it outlines the subtraction method where monthly production rates are forecasted for the existing zone, and then the upper zone allocation is determined through subtraction of the forecasted rate from the commingled rate. And an example is given below.

Q. All right. Let's assume that you have a Dakota well that you've produced for a sufficient period of time that you can establish a decline, and you know what percentage of that production is going to be attributable to the Dakota. You then recomplete it and add the Mesaverde. How does the formula work?

A. Well, let me run through that example. For instance, if the forecasted Dakota rate was 300 MCF a day, you would commingle with the Mesaverde. Let's say the commingled rate, then, is 750. You merely subtract the two to get your upper-zone rate and determine your percentages through simple division.

Q. And at that point can you fix the percentages and leave them fixed for the remaining productive life of the commingled stream?

A. You could.

Q. All right. Let's turn to the supporting data that you have presented to justify your recommendations. If you'll turn to Exhibit 31, identify and describe this.

A. Exhibit 31 and the next four exhibits depict normalized production curves for the five producing horizons. And let me briefly state how those were calculated.

A production database was built for each producing horizon, and each individual well flowstream was normalized back to a time zero. Those individual wells were summed and then divided by the active number of wells per month to get a normalized flowstream. This is shown by the black squares.

A decline was then best fit through that production, shown by the red line. As a double check to this best fit, the actual cum was fit with the calculated cum. Now, the actual cum is shown by the blue triangles, and the calculated cum by the purple line. That just ensures that your best fit is, indeed, your best fit.

The boxes at the bottom of these plots show normalized decline profiles. For the Dakota you see an average initial rate of 437 MCF a day with a 52-percent decline your first month -- or your first year, excuse me -- 19-percent decline your second year, and then an 8-percent final decline, for an EUR at 852 million cubic feet of gas.

Q. Have you followed this same methodology for the Mesaverde?

A. Yes, I have.

Q. And how is that illustrated?

A. Exhibit 32 shows the Mesaverde normalized production plot. As you can see, a very similar decline profile to the Dakota. You have a higher IP and a higher EUR.

Q. Have you gone through the similar methodology for the Chacra production?

A. Yes, the Chacra which is depicted as Exhibit 33, and the Pictured Cliffs which is shown by Exhibit 34.

Q. And then finally the Fruitland production on Exhibit 35?

A. Yeah, the Fruitland production on Exhibit 35, as you can see, noticeably different due to the different producing mechanism of the coal versus the sand, and it shows up in the decline profile. You see virtually no decline the first two years, and then a 12-percent decline there on out.

Q. All right. Have you put all these together and displayed it on Exhibit 36?

A. Yes, those are summarized on Exhibit 36.

Q. All right, let's turn to the summary, then, and have you identify and describe your supporting reasons to show your allocation formulas are fair, accurate and reliable.

A. As you can see, the PC, Chacra, Mesaverde and Dakota all exhibit similar decline trends. Those are summarized in the table below. Particularly, look at the decline for the first 12 months: 52 percent, 55 percent, 55 percent, 51 percent. All very, very, very close. The Dakota and Mesaverde next-year decline and final declines are also very similar.

The Fruitland Coal, obviously, is very different, and a fixed allocation formula should not be used for that. However, for the remaining four you could use fixed allocation formula with confidence.

Q. Let's turn to the final portion of your presentation and talk about your analysis of the various reservoirs in terms of whether they're marginal or not. You recall in Rule 303 you need to satisfy the requirement that at least one of the zones to be commingled must be marginal.

A. That's correct.

Q. Let's look at the next three exhibits, starting with Exhibit 37, and have you identify how you have made this comparison as to this issue.

A. Okay, the next three exhibits will show the economic data that was discussed.

The Exhibit 37 shows the development costs for various development scenarios, and I've tried to incorporate virtually all potential possibilities in this exercise. It lists the drilling costs -- these are all gross costs, by the way -- completion costs, facilities costs and then your annual operating costs for a number of different scenarios: singles, duals and commingles.

Q. Okay. Once you have made the cost spreadsheet what, then, did you do in determining which, if any, of these zones were going to be marginal or nonmarginal?

A. For each of these scenarios, given the costs shown here and the normalized production shown previously, I ran an economic case for each of these. Let's turn to Exhibit 38 and have you identify and describe this display.

A. Okay. Exhibit 38 is a graphical depiction of the effects of completion type on project economics for Mesaverde and Dakota Projects.

The top graph plots net present value versus development costs and shows three production flow streams, green being Dakota, red being Mesaverde and the blue triangles being the combined flowstreams. The vertical lines represent average costs for the typical type of completion listed, a single completion, commingled completion and a dual completion.

The bottom graph lists the same thing, except internal rate of return is plotted versus development costs.

And it's clear from these two plots that the maximum value is realized through the commingled development scenario.

Q. All right, let's look at the top plot. If you're looking at a single completion, that obviously costs less than either a commingled or a dual well, except its net present value to the unit is substantially less than either of the other two methods?

A. That's correct.

Q. And as you compare commingling to dual, the dual costs are substantially higher, and therefore you can achieve a higher net present value by commingling that production?

A. That is correct.

Q. Okay. Let's turn to the major summary sheet on Exhibit 39 where you have displayed your economic comparisons, you've arrived at some comments, and let's go through the various examples of what you finally conclude. Let's start with the conclusion. When you look at all these reservoirs and the various economic components, is there a single reservoir that represents the opportunity to be economic?

A. There is a single scenario that represents an economic project for Conoco, and that would be the Mesaverde-Dakota commingle.

Q. Okay. All other reservoirs, apart from the Mesaverde, is there any doubt in your mind that in the unit they are, in fact, marginal?

A. No doubt whatsoever.

Q. Have you come to the conclusion that you have to use the Mesaverde in combination with one of these other marginal reservoirs in order to recover gas from both the Mesaverde and the marginal reservoirs that you would not otherwise recover?

A. Yes, the Mesaverde must be involved --

Q. Okay.

A. -- for a development project.

Q. Yes, sir. All right, describe for us how you have prepared the spreadsheet and what conclusions you're reaching about these various types of well profiles.

A. Okay, the table at the top summarizes the development economics. It shows the well profile, the development costs, reserves, and four economic indicators: net present value, internal rate of return, profitability index and discounted payback.

The comments at the right basically summarize the economic results. If you'll look at the Mesaverde single, it's listed as economic only in that it has a positive NPV. I'll explain later why we consider it marginal as a stand-alone project.

If you'll look at the graph at the bottom left, that shows a comparison of net present value for those development scenarios. And only three have noteworthy positive net present values: the Mesaverde single, the Mesaverde-Dakota dual and the Mesaverde-Dakota commingle, that being some $295,000.

The graph on the bottom right depicts a comparison of profitability index for those scenarios. Now, profitability index is a measure of capital efficiency that Conoco uses to internally rank their projects, and it's calculated by taking your investment and net present value, divided by your investment for -- on a net after-tax basis. It essentially measures your bang for the buck.

At Conoco we use an internal benchmark of 1.8 as a minimum criteria for development projects. As you can see from the graph, only one scenario exceeds that 1.8 cutoff, and that would be the Mesaverde-Dakota dual.

The end result is, a Mesaverde single or a Mesaverde-Dakota dual would not compete internally for funds within Conoco and would not be done.

Q. All right. Let me see if I understand. When you go to the table on the lower left, when you look at the various possible wellbore configurations in the unit, there is only three possibilities that warrant further investigation of whether they could be commercial.

A. Yes.

Q. That would be the Mesaverde single in green --

A. Yes.

Q. -- the Mesaverde-Dakota dual in blue, and then finally the Mesaverde-Dakota commingled in red?

A. Yes.

Q. As you further analyze the potential economics of those three, you move over to the table on the right. And when you apply your profitability index that Conoco uses, only the Dakota-Mesaverde commingle would be the wellbore configuration approved to be drilled?

A. That's correct.

Q. The profitability index, the 1.8, what does that mean?

A. As far as the Conoco hurdle?

Q. Yes, sir.

A. It means that --

Q. You get your cost back 1.8 times? Is that what it says?

A. No, not necessarily. A lot of factors are involved, and it's essentially your net present value plus your investment, divided by your investment, on a net, after-tax basis.

Q. Okay. And that's using a pretty optimistic number anyway, isn't it?

A. Yes, Conoco uses a nine-percent discount rate, which is optimistic compared to a lot of companies who use 10, 12. I've seen as high as 20-percent discount rates in other operators' economics.

Q. Summarize your conclusions for us, Mr. Majcher, on the economics in terms of how you forecast the future opportunity in the unit to recover the remaining gas from these various reservoirs.

A. Well, any remaining gas that could be accessed through the Dakota formation will only be accessed through development drilling, commingled with the Mesaverde.

For the other horizons, as you can see, they are not stand-alone development projects. That gas would be accessed through selective recompletions.

Q. In terms of the allocation formula, have you concluded that the methods are fair and equitable so that each interest owner, regardless in what participating area they may have an interest, will receive their appropriate share of that production?

A. Yes.

Q. In your conclusion, would approval of this Application be in the best interests of conservation, the prevention of waste and the protection of correlative rights?

A. It will.

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

We move the introduction of his Exhibits 16 through 39.

EXAMINER STOGNER: Exhibits 16 through --

MR. KELLAHIN: -- 39.

EXAMINER STOGNER: -- 39 will be admitted into evidence at this time.

Thank you, Mr. Kellahin.

Mr. Busch, do you have any questions?

MR. BUSCH: I don't have any questions, Mr. Stogner.

EXAMINER STOGNER: Okay.

EXAMINATION

BY EXAMINER STOGNER:

Q. On Exhibits 25 and 26, you went through some schematics and some completion techniques, commingle versus dual.

A. Yes, sir.

Q. Does this hold true just for this unit, or would this hold true for any Blanco-Mesaverde-Basin-Dakota completion out in the San Juan Basin?

A. It would hold true for any Blanco-Mesaverde, Basinwide.

Q. Okay. Even in, perhaps, areas that have not been -- that could be considered wildcat areas that haven't produced in some time, or back during the initial phase of the development of these two pools?

A. Well, knowing what we know today, we have a lot of experience, a lot of history. I don't know what was done in the early days, but this methodology could have worked then as well as it does today, although reservoir pressures today are much less than they were originally, so you need a little help to get the liquids unloaded and to maximize your production through plunger lift.

Q. Would being able to get the reservoir information and the pressure datas with this method, assuming that this method was applied back during the initial phase, would we have been able to get as much information as you have now?

A. Possibly.

Q. Possibly.

A. I don't see why not.

Q. The reservoir information that you have given me, was that primarily collected by single completions, single producers, if you will, as opposed to, say, commingled productions?

A. What -- Exactly what information are you referring to? The production --

Q. Reservoir production figures.

A. The production data was pulled from *Dwight's Energy Data*, so it was either individual well flow streams prior to commingle, which is the majority of that -- I shouldn't say the majority of that, but a lot of it -- as well as recent completions that show the advantages in plunger-lift technology.

I limited -- If you'll note on the top of those normalized plots --

Q. I'm sorry, which plots?

A. Those would be Exhibits 31 through 35. For instance the Dakota, for these normalized plots I included only wells drilled since 1980 so that I could make sure that I was comparing wells that have modern completion and operating practices.

The same is true for the Mesaverde and others. Well -- Yeah.

For the Mesaverde and Dakota it only includes wells from 1979, 1980 to the present day. It excludes any earlier completions.

Q. Okay. Now, I'm not familiar with the process as is presently being done on administrative applications. So since we're here today to present a reference case, would you explain to me on a step-by-step basis how an application is made on a new well and an existing well, and then how this process, or how the order today which Conoco seeks, how that would change, how would it benefit and what would be eliminated?

Like I said, I don't do these so I'm not familiar. So we're going to have to go on a step-by-step basis on an application as is presently being presented or turned in today to the Commission.

A. Well, typically a C-107 form would be submitted with supporting data to verify the pressure criteria. And also each interest owner would be notified. In our case, those are very numerous, near 300.

So under a reference case, the notification would be eliminated, saving a lot of money and a lot of time. And also, the pressure data exemption would be eliminated based on what we've shown here today.

Q. Okay, how about the allocation formula?

A. How is that typically handled?

Q. Yes, and how will that be handled subsequent to this order?

A. Actually, that will be handled very similarly -- Correct me if I'm wrong, Tom, but in the past we submitted the downhole commingle application to this office for approval and then submitted the allocation formula to the Aztec office for approval. And that wouldn't change.

Q. Okay.

A. Of course, the allocation formula supporting data would be required in either instance.

Q. How about the issue of crossflow occurring? How is that presently handled? Is that along with the pressure data?

A. Based on the pressure data that I've analyzed and the reservoir data that I'm aware of, in my opinion there's no danger of crossflow. And we haven't seen any lost production, *per se*, due potential crossflow.

These wells, under producing conditions, will flow to the point of least resistance, which is the surface, and they're never shut in long enough to where we even have the problem of crossflow.

Q. How 303 B, subpart (6)? This talks about the BTU content of each of the zones commingled. How is that presently handled and --

A. The BTU content is currently submitted on Form C-107, and will continue to be submitted on Form C-107.

Q. So that would not change?

A. That's correct.

Q. Okay, Part 7 talks about whether a zone is currently producing or shut in. That wouldn't change, would it?

A. I'm sorry, I don't understand the question.

Q. Okay, I'm just reading through the criteria, which I'm assuming you're familiar with. You're probably more familiar with it than me, because, like I said, I do not process the administrative applications.

A. Okay.

Q. It states, Statement that each existing zone is either currently producing or shut in, and then it goes on to ask if each zone is marginal and, if it is shut in, give the date of last production, and then it currently talks about -- or it talks about the current producing interval and for any new zones in the production histories.

Would that -- How is that currently handled?

A. Well, that wouldn't be affected by the reference case. All those continue to be documented on C-107.

Q. Okay. And we talked about the allocation formula.

Do you know how many wells are presently downhole commingled in this unit area, roughly?

A. I don't have a number for you on that, but it's --

Q. How about a percentage? Downhole commingling of some kind?

A. I would say maybe 25, 30 percent is a good number.

Q. Okay. What would be the methodology, assuming that the order is issued subsequent to this case? For some reason I visualize all these wells shown on Exhibit Number 1, everything, all the downhole equipment being pulled and a massive perforation going on between everything from the base of the Dakota to the top of the Fruitland Coal.

Is that the intent of this order?

A. No, the intent is not -- The intent is to eliminate the notification and the pressure exemption, primarily for the Mesaverde and Dakota. If you envision a massive work program involving recompletions, those have not been studied nor economically assessed.

I believe in the future, once our development program is done, we will look at selective recompletions. Of course, by that time the Mesaverde-Dakota pressures will have decreased and pressure exemption will not be an issue.

Q. Would such an order allow additional perfs that would not otherwise be attempted -- Say you have a long-standing Blanco-Mesaverde-Basin-Dakota completion and there is a lot of area up here that hasn't had any Fruitland Coal, say. Would it allow -- Or what's your feeling on that? What would occur to coal development in this area?

A. As far as coal development, that's currently operated by Amoco. We will take over operatorship in approximately twelve months.

We don't have a coal program, *per se*, right now.

That needs to be addressed in the long-range program. But there would be the possibility of maybe some plugbacks and recompletions to the Fruitland Coal if economic.

Again, those reserves and flow streams are a lot less than the Mesaverde-Dakota, as you can see. And again, I don't envision a blanket perforating-type scenario up and down the wellbore because, one, it's an operational nightmare if you've got more than two zones, maybe even more than three zones. And I'm not aware of us doing a trimingle as of yet.

But again, I don't envision a monster program of recompletions in the near term.

Q. Okay, I'm sorry, I'm confused now that you mention the Fruitland Coal. The Fruitland Coal is being operated in this unit by somebody else?

A. It's being operated by Amoco; we're partners with them. And they had attempted a nitrogen flood a few years ago; it had failed. And part of the conditions of that was that the operation of the Fruitland Coal goes over to Conoco 18 months after the ceasing of the nitrogen flood.

There's only 14 Fruitland Coal wells currently in the unit, 12 of which are producing.

Q. And how are those wells being -- How are those 18 wells being produced?

A. Those 12 wells are being produced --

Q. What I mean by that, singly -- ?

A. Singly, yes.

Q. By Amoco?

A. Yes.

Q. Then why are you seeking authority to downhole commingle Fruitland Coal at this time?

A. Because soon we will be operating those wells. In fact, there's talk with Amoco of us taking over operatorship immediately.

Q. How about the Chacra completions and production? Is that being -- Most of those wells, are they being done singly, and are they being done by Conoco or somebody else?

A. The Chacra wells are operated by Conoco. Some of them are singles, some of them are commingled with the Pictured Cliffs.

And there are some Pictured Cliffs that are commingled with the Mesaverde. Those are mature wellbores that would be uneconomic if they weren't already commingled.

EXAMINER STOGNER: Any other questions, Mr. Kellahin?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: You may be excused.

Mr. Busch, I'm curious what the Aztec District Office -- if they have a position in this matter.

Obviously you've come down to a great expense, so I'd like for the Aztec Office to make a comment, since you're here, and make it worthwhile and on the record.

MR. BUSCH: The nature of the Application to establish a reference case for the commingling of those many zones was our concern, on how you were going to handle, and especially the Mesaverde formation.

New light is being shed on the Mesaverde in the Basin due to recent, you know, seismic profiles and other studies.

So we have to approach this, this Application, cautiously from that aspect, not knowing, you know, what the Mesaverde is going to be doing or capable of doing.

And then, of course, the Fruitland Coal -- I presume that you're looking at all of those based on a subtraction method?

MR. MAJCHER: That's correct.

MR. BUSCH: And we weren't sure what you were wanting to do with that, but it's clearer to us now. It's not as big an issue.

We have some concern about the original reservoir pressure question and -- but that's been made a real part of the record today, so I think there's enough evidence to consider that aspect of it.

EXAMINER STOGNER: Mr. Kellahin, do you have any comments at this time?

MR. KELLAHIN: Certainly, Mr. Examiner.

This is not a blank check to commingle production in the unit for any reservoir anywhere. We're not there.

This is a reference case. And that is distinguished from the continuing responsibility of Conoco to file on a well-by-well basis the C-107. Nothing you do here today eliminates that necessity.

So as Mr. Busch or Mr. Catanach or any of the other regulators look at each application that's filed, they will make a judgment about whether for that wellbore they will permit the Applicant to commingle one or more of these formations together.

The purpose of this case is to make the process easier for Conoco and for the regulators.

The first problem is the notice problem. To the best of my knowledge, perhaps with one or two exceptions, no one opposes commingling.

In the instances where I have seen an opposition filed, with a quick phone call the opposition is withdrawn. They filed the opposition because they didn't understand what was going on.

I appreciate the fact that in the San Juan Basin the Division has a huge historic inventory of information that might not have otherwise been captured and preserved, had it not been for the methods used. We are at the point, however, in the life of this unit where commingling simply is the only reasonable opportunity to continue to produce the reservoirs.

What we're seeking with this Application is to make the process easier, so that Mr. Stone and Mr. Catanach, when they look at these things, will have a case file where they can look and see what is being utilized for pressure and where it came from.

Here we're asking for a pressure exception. We think there's enough definitive evidence in the unit to satisfy that.

It doesn't remove the requirement to supply the information, and it does not preclude Mr. Catanach from disapproving the commingling. It is simply a reference point for him so that he doesn't have to do our homework and so that he can process these applications in an expeditious way.

The matter of the marginality of the reservoirs is simply, at this point, checking off blanks on the form. To the best of my knowledge, Mr. Catanach and Mr. Stone don't question the applicant's assertion of the marginality of a reservoir. Should they choose to do so in this unit, they may look at this reference case and examine Mr. Majcher's conclusions.

You may, if you choose to do so -- We request that you make a finding that all these zones except for the Mesaverde are marginal, and therein that supports that checkmark on the blank.

It doesn't remove any of the checkmarks. We have to fill it out properly and completely. It's simply a way to make the process easier. It is not approving any commingling for any of these wells.

What is missing at this point from the presentation -- and with your permission, I'll provide you an affidavit as to the notification so that you can satisfy yourself that every interest owner in this unit, all 200 and something of them, had the chance to come play today.

We have -- and I have marked as Exhibits 41 through 44 the various participating areas in the unit, so that you can visualize the fact that there is a difference of ownership, and that simply accounts for the fact that you have different participating areas.

In addition, Exhibit 40 is our certificate of notice, and I will supplement that with a landman's affidavit as to the reliability of these participating area maps and to the completeness of the notification list. But everybody that's getting a check in this unit is on that list.

In addition, all the offset operators to the unit were notified, and there is no one, to my knowledge, that has opposed the approval of this case.

And we would ask that with the submittal of that affidavit and the introduction of these additional participating area displays that you take this case under advisement and that you enter an order that grant's the Applicant's request.

EXAMINER STOGNER: Mr. Kellahin, I have -- This is the only -- second reference case I've had. And incidentally, the first one I had was one similar, to which I had alluded to, and that was a blanket check to perforate. And I'll refer -- I don't remember the case number, but Mr. Bruce, who is not here, well remembers that application.

How many reference cases have you been involved with or that you have found? Like I said, I've alluded to one that I've had. This is the second one. Do you know how many others have come forward?

MR. KELLAHIN: I'm going to guess, Mr. Examiner. I did two for Phillips, I've done six or seven for Burlington.

We're doing it based upon a practice developed out of discussions on Rule 303, and the idea is, instead of having areawide commingling approvals, to manage the approval process within the context of these units, we have the good fortune in the San Juan Basin that a lot of this production is unit production and that the units are generally a township, more or less, in size.

And it's a nice way to approach commingling, so that as you look at commingling within the unit, you gather together the data in one case file where we can look at the information to justify commingling.

And so that's how we've approached it. But in each instance, we'll continue to process these on an individual administrative basis.

And so that areawide blanket approval that you're thinking about is not applicable in this case.

EXAMINER STOGNER: Looking at 303 E, it states in there that such applications can come administratively or before a hearing. Has any of them gone administratively that you're aware of?

MR. KELLAHIN: A reference case?

EXAMINER STOGNER: Yes.

MR. KELLAHIN: The rule allows it to be processed administratively. Thus far, all reference cases have come to hearing.

EXAMINER STOGNER: In Conoco's filing this request, obviously you didn't -- or did you -- or did Conoco first approach Mr. Catanach to go administratively in this matter?

MR. KELLAHIN: I did not -- The practice has been to take all these to hearing, so it didn't even occur to me to suggest he would process this administratively.

We felt particularly concerned that because we're eliminating future notice to royalty owners and interest owners in this unit, that it was best served by having this docketed as a public hearing and having a full disclosure with witnesses under oath to make a record, so that we would not be subject to criticism for not providing an opportunity for that notice.

EXAMINER STOGNER: Good point.

Mr. Kellahin, what I'd like to do in this instance, I want to continue this case to -- what? August 27th. Not for additional testimony, unless it needs be. But what I'd like for Conoco and you and Mr. Stone, Mr. Catanach and Mr. Bush, is for you to prepare a rough draft order addressing these issues, and where it's -- and run it through them, so all concerned in this instance can have an input about how the order should read.

And if a cooperative order -- or an order is issued that has the cooperation of everybody -- and hopefully that's what will occur. However, that's the reason I'm continuing it to the 27th [*sic*] of August, in case something does come up where -- needs to be issued or a decision needs to be made, then I can do that at that time.

What that would do is to allow you to get a rough draft order together with everybody's cooperation and everybody's review of it. When I say "everybody", Dave Catanach, Ben Stone, Mr. Busch --

MR. KELLAHIN: I understand.

EXAMINER STOGNER: -- and of course yourself, representing Conoco. And hopefully all concerns can be addressed.

Looking into the future, I'd like to see some sort of precedents be set where then an Applicant would feel -- can go to the administrator, or perhaps even -- because you brought some concerns up.

This gives a public notice. That means a lot more at a hearing level. Perhaps in the absence of objection an order can be issued.

Forgive me for not having the expertise of processing these administratively, but I feel all -- everybody will have a chance, then, to make sure that everybody's playing in the same ballpark and that perhaps if there was any misgivings in the District level, such as mine were, *carte blanche* -- There are some operators, you know, that do that.

MR. KELLAHIN: I understand. And perhaps it gives us an opportunity to have a fresh point of view from your position. The hearing would be on the 21st of August.

EXAMINER STOGNER: The 21st? Okay. So let's continue this matter for the 21st.

I don't feel it will be necessary for additional testimony to be made. What I'd like for you at that time, to be able to present a rough-draft order that we can make effective at that time, and that would allow everybody's input.

MR. KELLAHIN: Well, let me suggest that we would also present to you a filing of one of these applications the way it would be packaged in the absence of a reference case, and then we'll give you an example or an illustration of how the Division would receive a commingling application with approval of this case.

In addition, one of the things that we have considered and would like you to consider is that in certain of units it might be reasonable to suggest that the processing of this case go to the District, with the guidance of these orders, and that certain of these units, like this one, don't require the attention of Mr. Stone and Mr. Catanach, where they could apply their resources to looking at other commingling cases.

So I will try to put those in the form of an order. We will circulate it to all the regulators that are involved, and we will be back to see you on the 21st.

EXAMINER STOGNER: Now, that's the kind of thought process, that you just mentioned, which I had in mind.

So with that, at this time we'll continue this matter to August 21st, awaiting a rough draft order.

So with that, this case is adjourned.

And let's take a ten-minute recess before the next case.

(Thereupon, these proceedings were concluded at 10:00 a.m.)

* * *

I do hereby certify that the [illegible] a complete record of [illegible] the Examiner hearing of [illegible] 11815 heard by me on 24 July 1997.
[signature], Examiner
Oil Conservation Division

CERTIFICATE OF REPORTER

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

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

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

WITNESS MY HAND AND SEAL July 27th, 1997.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998